Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

FORT NELSON CARBON CAPTURE AND STORAGE FEASIBILITY STUDY – A BEST PRACTICES MANUAL FOR STORAGE IN A DEEP CARBONATE SALINE FORMATION

Plains CO_2 Reduction (PCOR) Partnership Phase III
Task 9 – Deliverable D100

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EXECUTIVE SUMMARY

The Plains CO_2 Reduction (PCOR) Partnership, led by the Energy & Environmental Research Center, and Spectra Energy Transmission (SET) have investigated the feasibility of a carbon capture and storage (CCS) project to mitigate carbon dioxide (CO_2) emissions produced by SET's Fort Nelson Gas Plant (FNGP). FNGP is located near the town of Fort Nelson in northeastern British Columbia, Canada. If SET were to decide to implement the Fort Nelson CCS project, it would result in the storage of >2 million metric tons a year of CO_2 in a deep saline formation. The PCOR Partnership applied geologic characterization; modeling; risk assessment (RA), and monitoring, verification, and accounting (MVA) strategies using an integrated, iterative process to produce superior-quality results during the project feasibility period. The Fort Nelson efforts serve as the basis for a Best Practices Manual (BPM) that offers stakeholders insight and guidance on geological storage of CO_2 in a deep carbonate saline formation.

Since 2009, SET and the PCOR Partnership conducted substantial efforts to collect baseline characterization data on potential sink and sealing formations in the Fort Nelson area. Those data were used to create static petrophysical models of potential CO_2 storage reservoirs and to conduct dynamic simulation modeling of potential injection scenarios. The baseline characterization data and modeling results were, in turn, applied to a RA of potential operational scenarios. While a final injection strategy has not yet been determined for FNGP, a draft MVA plan for a hypothetical injection scheme has been developed using assumptions that are based on the feasibility study efforts. The risk-based draft MVA plan covers the surface, near-surface, and deep subsurface environments in the FNGP area and includes specific technologies, spatial locations of measurements, and baseline data necessary to address critical project risk and regulatory requirements and identify any deviations from expected conditions in a timely manner. Although specific techniques and procedures may change as the project proceeds, the project's philosophy of integrated, iterative geologic characterization, modeling, and RA will ensure that MVA strategies remain fit for purpose and cost-effective and have the greatest potential for success throughout the project's lifetime.

The results of characterization, modeling, and RA efforts suggest that the Fort Nelson area has sink and seal conditions that make it an exceptional candidate location for large-scale CCS. The potential sink formations include areas with excellent injectivity characteristics. The storage capacity of the Devonian carbonate formations in the area has been estimated to range from 140 million to 240 million metric tons, sufficient to support the full anticipated formation CO_2 emissions of FNGP for several decades. The extremely low permeability, high geomechanical competence, and tremendous thickness (>500 m) of the overlying Muskwa and Fort Simpson shale formations mean that they will serve as excellent seals. Climate and terrain will hamper the deployment of some MVA technologies, but implementation of an effective MVA plan for both surface and subsurface environments can be achieved by the application of proven approaches used by the oil and gas industry in the area. Acknowledging the need for longer lead times for planning and elevated levels of coordination between different technical teams and service providers will also be keys to successful MVA deployment and operation at Fort Nelson.

The key elements for the Fort Nelson efforts and a hypothetical draft MVA plan were examined in the context of how they address the guidelines enumerated in the Canadian Standards Association (CSA) Standard CSA Z741-12 Geological Storage of Carbon Dioxide. The Fort Nelson efforts to date meet or exceed a majority of the CSA standard specifications. Most of the deficiencies are in topic areas that would not typically be addressed in the feasibility study phase of a project but, rather, are more appropriately addressed after a "go" decision has been made, during the design phase of a project.

With respect to broadly applicable best practice elements that were identified over the course of the Fort Nelson project, several key observations and recommendations are offered.

Deep carbonate saline formations may serve as effective, high-capacity locations for the large-scale geological storage of CO_2. However, carbonate formations are inherently heterogeneous and anisotropic with respect to rock properties, including porosity and permeability distribution. This makes characterization of carbonates challenging and can lead to a high degree of uncertainty in the interpretation of results, especially with respect to predicting the injectivity and storage capacity of a formation. Therefore, detailed rock characterization from multiple wells and the correlation and integration of the data with other data sets (e.g., seismic surveys, hydrogeological studies) are critical to reducing that uncertainty.

The injection of CO_2 and its mobility in a deep carbonate saline formation is closely analogous to conventional oil and gas production operations. Therefore, site characterization and modeling exercises should follow standard practices, protocols, and workflows that are commonly applied in the oil and gas industry. Those approaches are also generally well accepted and understood by the regulatory community.

Oil and gas industy activities have been conducted in challenging climates and terrains for decades. Over that time, industry has developed proven, cost-effective, and environmentally sustainable approaches to installing, operating, and maintaining production and injection projects that serve as excellent analogs for how to conduct CCS projects in extreme environments.

Robust RA efforts can provide a technically defensible basis for a cost-effective MVA strategy that addresses the concerns of multiple stakeholders. MVA technologies should be deployed at locations selected according to their surface accessibility and spatial relationship to the predicted plume. The MVA technology matrix should include monitoring of the surface and near-subsurface environment (e.g., surface water, groundwater, and soil gas), geophysical logs, wellbore integrity monitoring, and a variety of downhole instruments (e.g., pressure and temperature sensors) and remote sensing tools. While traditional 3-D seismic surveys should be considered and deployed where cost-effective and appropriate, areas with accessibility issues and/or geologic conditions that are not conducive to seismic data collection should not be precluded from being candidates for hosting a CCS project. As long as there are means of delineating the geometry of the plume in a technically defensible manner that are acceptable to the regulator, then the site should be considered for CCS.

FORT NELSON CARBON CAPTURE AND STORAGE FEASIBILITY STUDY – A BEST PRACTICES MANUAL FOR STORAGE IN A DEEP CARBONATE SALINE FORMATION

INTRODUCTION

In 2003, the U.S. Department of Energy (DOE) established seven Regional Carbon Sequestration Partnerships (RCSPs) to help develop the technology, infrastructure, and regulations to implement large-scale carbon dioxide (CO_2) storage in different regions and geologic formations in the United States.

Phase III of the program includes the implementation of large-scale (1 million metric tons or more total) projects that will demonstrate the long-term, effective, and safe storage and utilization of CO_2 in geologic formations throughout the United States and portions of Canada. The goals of the demonstration projects are to:

- Provide scientific data to validate the capacity estimates to within ±30% for deep saline formations, where few data currently exist.

- Assess the effects of reservoir heterogeneity on the performance of the storage operations to contact the pore space and maintain injectivity.

- Validate the reservoir models against field data, implement mitigation strategies to reduce potential hazards, and verify the fate of the injected CO_2 using the most advanced monitoring networks applied to date.

- Demonstrate that the projects are representative of the regional geology to store large volumes of CO_2 emissions generated from major point sources.

The Plains CO_2 Reduction (PCOR) Partnership, led by the University of North Dakota Energy & Environmental Research Center (EERC), together with its partner Spectra Energy Transmission (SET), conducted the Fort Nelson Carbon Capture and Storage (CCS) Feasibility project (Fort Nelson project) in order to help achieve the program goals. It is important to note that as of September 2014, SET had not advanced the Fort Nelson project beyond the feasibility study phase. However, the lessons learned through the feasibility study can be readily applied to future large-scale CCS projects in similar geologic and geographic settings. The experience gained during the Fort Nelson project serves as the basis for this best practices manual (BPM) for CO_2 storage in a deep carbonate saline formation.

PHILOSOPHY OF THE BEST PRACTICES MANUAL

DOE has established a process whereby information is conveyed to CCS stakeholders through the use of BPMs. These documents serve to provide specific information and lessons learned regarding key aspects of the characterization, development, and implementation phases of large-scale CCS projects. The information compiled here is intended to increase awareness of the steps required to use an iterative, adaptive management approach to determine the technical viability of commercially implementing a CCS project. Specifically, this BPM is a technical guide to conducting a feasibility study for storing CO_2 in a deep carbonate saline formation. The target audience for this BPM includes project developers; regulatory officials; national, state/provincial, and local policymakers; and the CCS scientific and engineering community. The information in this BPM is intended to serve as a guide to other regions where deep carbonate formations may serve as targets for geological storage of CO_2. The approach of this BPM is to present and describe the critical steps that must be taken prior to undertaking a large-scale CCS project, specifically, site characterization, modeling and simulation, risk assessment (RA), and planning for monitoring, verification, and accounting (MVA). The approach and results of the work that was conducted by SET and the PCOR Partnership for the Fort Nelson project are presented as an example of the application of this iterative, adaptive management approach.

OVERVIEW OF THE PHASE III FORT NELSON PROJECT

The Fort Nelson project is located in northeastern British Columbia within the northwestern portion of the Alberta Basin (Figure 1).

From 2009 to 2012, the PCOR Partnership, led by the EERC, and SET conducted activities to investigate the feasibility of a CCS project to mitigate CO_2 emissions produced by SET's Fort Nelson Gas Plant (FNGP) (Figure 2) as a waste stream from natural gas processing. The gas stream produced by FNGP is over 94% CO_2, with up to 5% hydrogen sulfide (H_2S) and a small amount of methane (CH_4), and as such is referred to as a "sour" CO_2 stream. The concept for the CCS project was to compress the sour CO_2 stream to a supercritical state and transport it via pipeline approximately 15 km to an injection site. The injection target, or sink, being considered consists of brine-saturated carbonate rocks (limestone and dolomite) of a formation in the Elk Point Group. The proposed injection zone is capped by Fort Simpson and Muskwa shale 550 m thick, as shown in the stratigraphic column in Figure 3. These shale formations are expected to function as an impermeable seal. A technical team that includes SET, the EERC, and others conducted a variety of activities to 1) determine the geological, geochemical, and geomechanical properties of the target injection formation and key sealing formations in the vicinity of the injection site; 2) model the effects that large-scale injection of sour CO_2 may have on those properties as well as wellbore integrity; 3) evaluate the geologic risks of this injection process at local and regional scales based on results of the modeling effort; and 4) design site-specific, risk-based MVA technologies to ensure safe and cost-efficient long-term CO_2 storage.

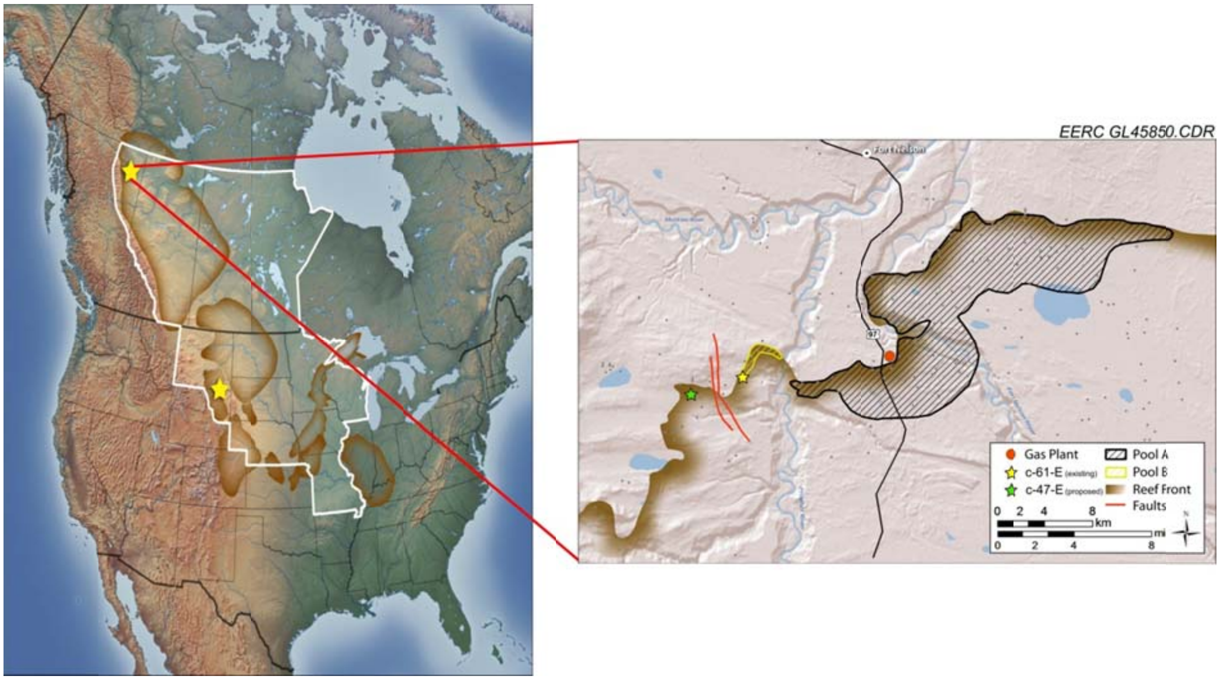

Figure 1. Map of the Fort Nelson project study area in British Columbia.

Figure 2. SET’s FNGP in northeastern British Columbia (photo courtesy of SET).

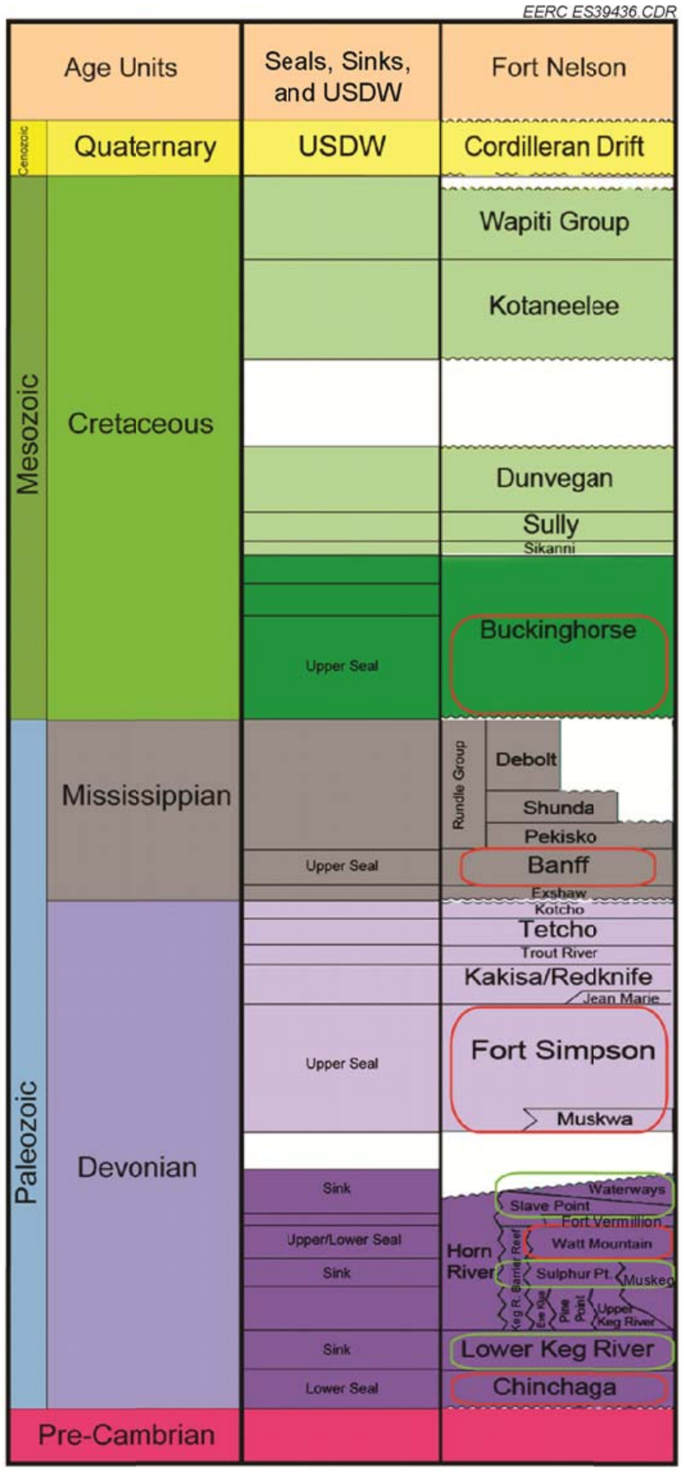

Figure 3. Stratigraphic column of the Fort Nelson area (modified from Sorensen and others, 2014b). The target injection zones for the sour gas are the Slave Point, Sulphur Point, and Lower Keg River Formations. The overlying Fort Simpson and Muskwa shales (~550 m thick) represent an impermeable seal (USDW is underground source of drinking water).

Project Drivers and Objectives

FNGP is one of the largest gas-processing plants in North America and is owned and operated by SET. The plant currently generates about 1.05 million metric tons of sour CO_2. This amounts to a total of about 1.0 million metric tons/year of CO_2 and 50,000 metric tons/year of H_2S. Because of the recent developments with shale gas plays in the Horn River Basin, a large expansion project is currently under way in the Fort Nelson area. Once at full capacity, it is anticipated that the Fort Nelson plant will be the largest single-point CO_2 emission source in British Columbia, generating approximately 3 million metric tons of CO_2 annually. Of that total, it is anticipated that approximately 2.2 million metric tons will be CO_2 that is removed from the incoming raw natural gas stream from production operations in the region (referred to as "formation CO_2"), while the other 0.8 million metric tons is generated by combustion of fuel as part of the gas plant operations. The Fort Nelson project would be focused on capturing, injecting, and storing only the formation CO_2, and all references to CO_2 in this document are meant to refer to formation CO_2. The Horn River shale gas coming into the plant is 10% to 14% CO_2 by volume. It is anticipated that over the next several years, the Horn River shale will be the focus of natural gas exploration and production in northeastern British Columbia, and as more Horn River shale gas is processed at FNGP, the amount of formation CO_2 generated at the plant is expected to increase significantly. These emissions will not go unnoticed by the provincial and federal governments as well as the public, but as of 2014, there was no driver (commercial or regulatory) in place to address the emissions.

Because of the projected emissions from the plant and the growing potential for greenhouse gas regulation by local and/or federal governments, SET recognized that the environmental footprint from this one plant alone could become a significant liability. Thus SET has a strong incentive to find a technology that allows the continued expansion of its gas-processing operations while maintaining an environmentally conscious image.

Therefore, SET proactively set out to explore the addition of CCS technology to its FNGP. The goal of CCS at FNGP would be to capture the stream of sour CO_2 that is separated by the current gas-processing operations and inject it into a deep saline formation for long-term storage. Presently, this sour CO_2 is processed in an existing sulfur plant to recover elemental sulfur, and the residual CO_2, SO_2, and H_2S is passed through an incinerator and vented to the atmosphere. Several positive outcomes may be achieved by the approval and implementation of the Fort Nelson project, including 1) securing SET's core business in the long term by demonstrating its ability to process sour gas in an environmentally friendly manner; 2) maintaining SET's leadership role in acid gas (CO_2 and H_2S removed from raw natural gas) injection and storage technologies in a growing industry; 3) very little change in the cost of operating FNGP as the cost of compression will be about equal to the cost of running the sulfur plant, and as a result of shutting down the sulfur plant, there will be less SO_2 released into the local air shed; 4) gaining the potential to earn CO_2 credits (depending on emerging regulation); and 5) enhancing SET's corporate image based on reliability and responsible environmental stewardship. These attributes are important for both SET's customers and the public's perception of the company. The implementation of CCS on a worldwide scale has been slow to happen because of technological, economic, and social challenges as well as lack of a clear regulatory policy and carbon market. However, should SET decide to implement CCS technology, the Fort Nelson project has several advantages that will facilitate success:

- SET has a long history of safe and effective acid gas injection, with on the order of 200,000 metric tons of CO_2 and 300,000 metric tons of H_2S injected annually across eight of its gas-processing plants in western Canada.

- Unlike most prospective CCS projects in North America, the Fort Nelson project does not have the high costs associated with outfitting a plant with CO_2 capture technology since the sour CO_2 is already separated and captured as part of natural gas processing; however, the cost of compression, cooling, dehydration, transportation (pipeline), and sequestration remains.

- The prospective injection site is located in a remote area where population density is low and local public support is expected to be strong because of the history of natural gas processing, the economic benefits the plant brings to the local community, and SET's long-standing reputation as a safe and environmentally responsible operator.

- There are no incremental fuel gas requirements with the Fort Nelson project. Most CCS projects require a significant amount of additional fuel gas to be burned in order to drive the new compression required to inject CO_2. In Fort Nelson's case, the fuel gas that would have been burned to perform sulfur recovery becomes available for use as fuel for compression because the sulfur recovery operations will be shut down as a result of the CCS operations.

- The storage reservoir is far below any usable water and is topped by a very laterally continuous, 500-m-thick cap rock that preliminary data indicate will successfully contain the injected sour CO_2.

- The British Columbia provincial government considers CCS to be a major component of its greenhouse gas reduction strategy and is supportive of further development of the local natural gas resources.

- The federal governments of Canada and the United States, as well as the provincial government of British Columbia, have supported the Fort Nelson project through cash and in-kind contributions.

FNGP CARBON CAPTURE FACILITY

FNGP receives raw natural gas from a variety of producers who deliver it to the plant through existing raw gas transmission pipelines (~1 Bcf/day). One of the natural gas sources is the Horn River shale basin, the largest resource play in Canada and potentially one of the largest shale gas deposits in North America.

A schematic of the plant includes separation for the removal of natural gas liquids and water, gas sweetening using an amine scrubber, and further dehydration prior to compression and off-site transport (Figure 4).

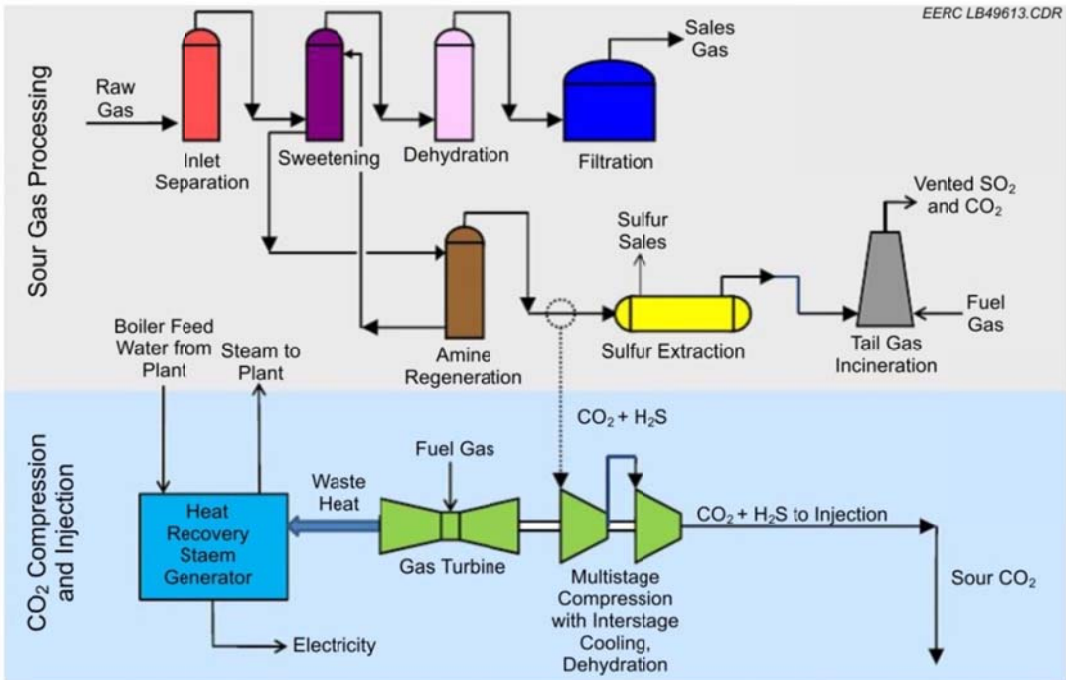

Figure 4. Schematic of the Fort Nelson CCS facility (image courtesy of SET). The sour gas is removed from the raw natural gas using an amine scrubber. The sour gas that is generated during the regeneration of the amine scrubber solution is currently treated to remove the sulfur, after which it is incinerated. As part of the plant expansion, this treatment of the sour gas will be eliminated and the sour gas will be injected into a subsurface saline formation.

The plant also includes an amine regeneration unit, which produces a regenerated amine solution that is recirculated back to the gas-sweetening unit and a sour gas consisting of CO_2 and H_2S. Currently, the sulfur is removed from the sour gas and sold; the treated sour gas is incinerated, yielding a vent gas that contains CO_2 and sulfur dioxide (SO_2). As shown in Figure 4, the plant expansion will eliminate the recovery of sulfur and incineration of the treated sour gas. In place of these process steps, the sour gas will be compressed and injected into the deep subsurface where it will be stored.

CARBON TRANSPORT AND STORAGE

The sour CO_2 for subsurface injection is expected to have a general composition of 95% CO_2, 4% H_2S, and 1% CH_4. The geological storage formation must be capable of handling up to 2.2 million metric tons per year of sour CO_2. In addition to being able to accept these design volumes of gas, the reservoir also needs to be large enough to store the anticipated volume of sour CO_2 over the lifetime of the operation (i.e., ~20 to 50 years) and beyond (i.e., >100 years), and the containing formations and injection, production, and monitoring wells also need to exhibit long-term integrity.

The captured sour CO_2 will be transported approximately 15 km to one of two possible subsurface injection points, c-47-E and c-61-E (Figure 5). The potential of these injection points to accept the anticipated volume of sour CO_2 and the impacts of these injections on the local and regional environment were evaluated using both static and dynamic simulation models. Of particular concern is the potential for the injected sour CO_2 to migrate and impact the deposits of natural gas in the region (i.e., Gas Pools A and B, Figure 6). The results of these evaluations are presented later in this report.

INTEGRATED APPROACH TO PROJECT IMPLEMENTATION

The PCOR Partnership applies an integrated approach for implementing large-scale commercial CCS projects that involves feedback loops between the program elements of site characterization, modeling and simulation, RA, and MVA (Gorecki and others, 2012) (Figure 7). Knowledge gained in each program element is critical to understanding or developing the other program elements. For example, as new knowledge is gained during site characterization, it can reduce the degree of uncertainty in the geological assumptions. This reduced uncertainty will then propagate through modeling and simulation, RA, and MVA efforts.

More specifically, for the Fort Nelson project, this integrated process was initiated with the completion of site characterization activities that were conducted to address three critical issues affecting the viability of the Fort Nelson site: 1) the capacity of the target formation; 2) the mobility and fate of the sour CO_2 at near-, intermediate-, and long-term time frames; and 3) the potential for leakage of the injected sour CO_2 into overlying formations, near-surface environment, or neighboring natural gas pools.

The integrated process began with a literature review of known geologic information for the region of interest to gain a broad-based understanding of the geologic systems that could serve as sinks (i.e., storage of CO_2) or seals (i.e., impermeable units to impede CO_2 vertical or lateral migration). Robust sets of relevant data to assist in describing the current subsurface geologic conditions, in particular those that relate to storage reservoir injectivity, capacity, and integrity, were acquired. These data were analyzed and interpreted to identify potential injection horizons and well locations for more detailed study. Once potential sinks and seals were identified, the data sets were then used as the basis for static and dynamic modeling activities to provide stakeholders and decision makers with insight regarding the viability of the area of interest with respect to CO_2 storage. RA activities were then conducted and used to identify which aspects of the program required additional characterization. Potential MVA technologies were identified that will ultimately serve as the primary means by which the storage operation can be managed from a risk perspective. This first iteration of work relied on information from readily available literature or publicly accessible databases, proprietary technical reports commissioned by SET, and a variety of data generated by the drilling of an exploratory well.

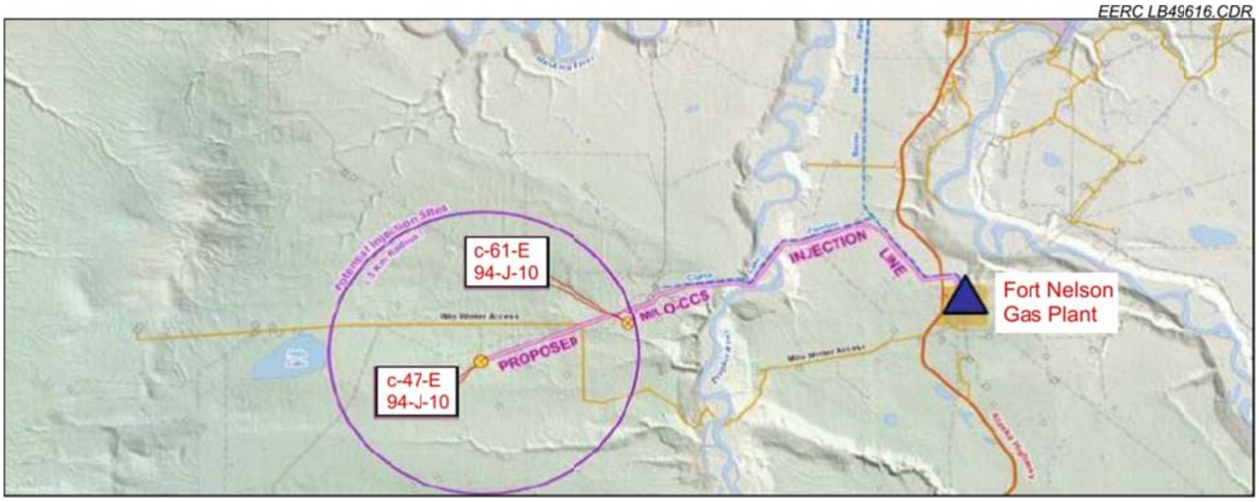

Figure 5. Pipeline for the transfer of captured sour gas to the point of subsurface injection. Currently, two subsurface injection points (c-47-E and c-61-E) are being considered (image courtesy of SET).

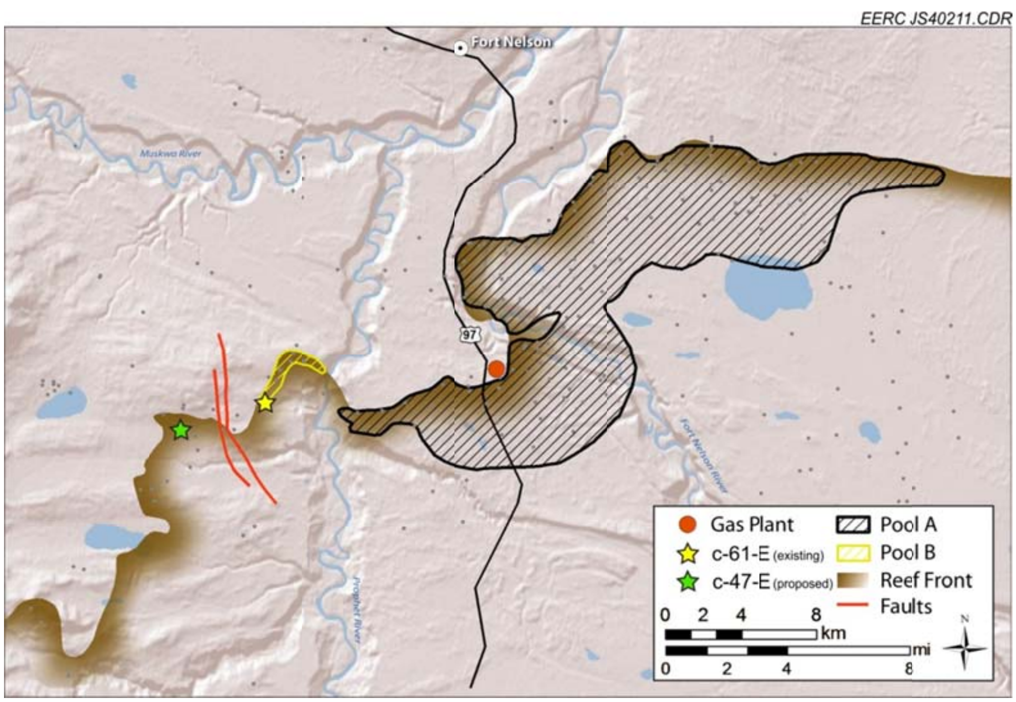

Figure 6. Site map showing the spatial relationship between the potential CO_2 injection points (c-47-E and c-61-E) and the nearby deposits of natural gas (Gas Pools A and B) (Sorensen and others, 2014b).

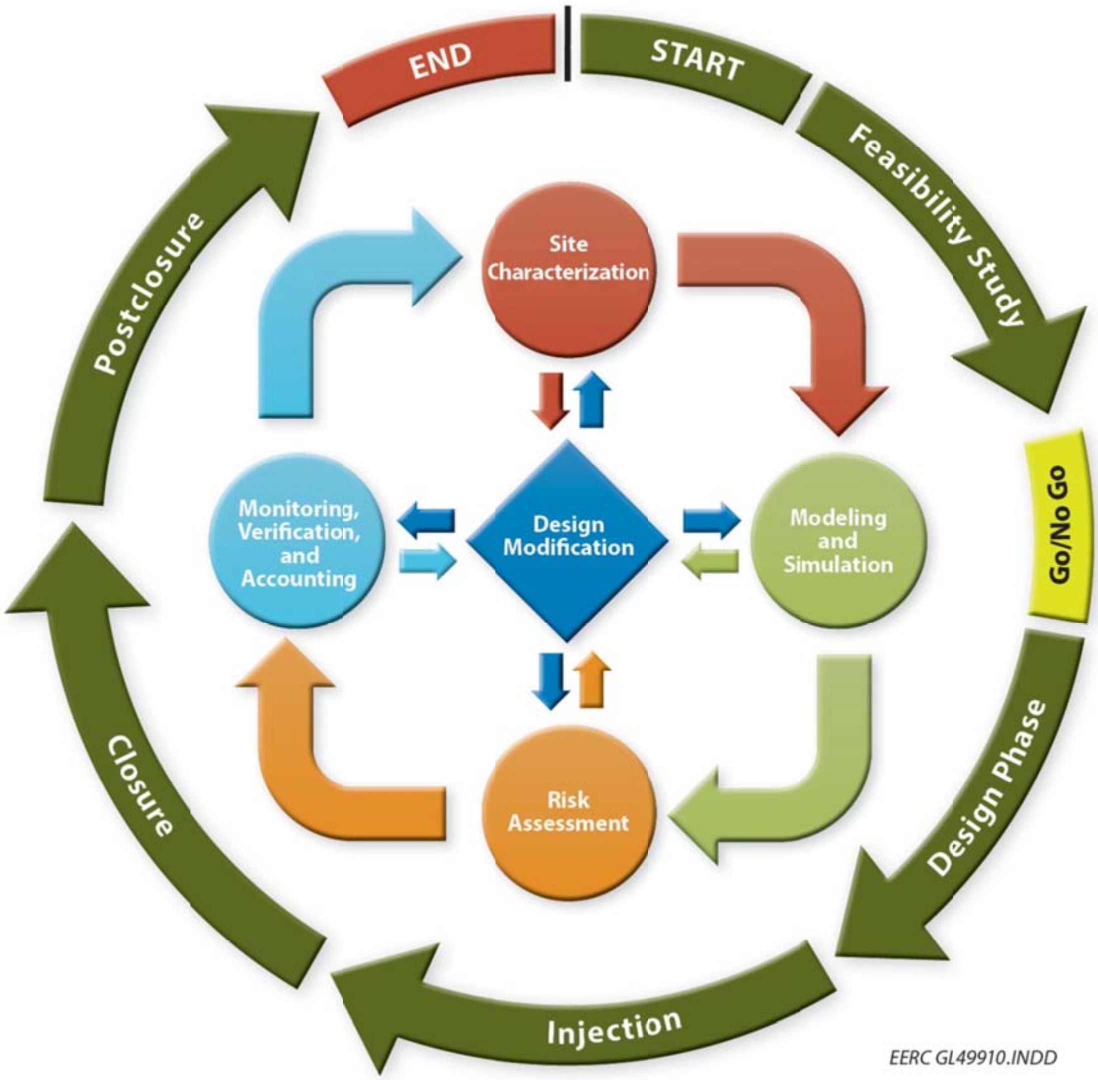

Figure 7. Integrated approach to project implementation: site characterization, modeling and simulation, RA, and MVA (modified from Gorecki and others, 2012).

Over the course of the project, the characterization, modeling, and RA activities were repeated, resulting in three versions of a reservoir model and two rounds of RA. These efforts continued to define additional data needs for the project. The results of the first several iterations of the integrated approach are discussed in this report. The reporting of future iterations, which are planned by SET, are beyond the scope of this document. The remainder of this report is organized into the following topic areas, which capture the components of the integrated approach:

- Geologic characterization
- Geochemical/petrophysical characterization
- Geomechanical characterization

- Petrophysical reservoir modeling
- RA
- MVA
- Conclusions

UNDERSTANDING THE SURFACE AND SHALLOW SUBSURFACE

Surface and Shallow Subsurface Characterization

The nature of the surface and shallow subsurface (depth <100 m) regimes of an area can and will have a major impact on the design, implementation, operation, and maintenance of a CCS project. Surface features that must be accounted for include the presence of major and minor bodies of water, land use, soil and vegetation types, and climate. Shallow subsurface features that must be evaluated include potential sources of potable groundwater. Any of these features can affect the accessibility of a potential injection or monitoring location, including the design and construction of pipelines, well pads, and other infrastructure that may be necessary to support a CCS project. These features are also typically the most sensitive from an environmental standpoint, and therefore, their characteristics need to be understood to ensure that they remain unaffected by CCS operations. Baseline information on these features is especially important as a means of comparison to determine if any future observed changes in shallow groundwater, soil gas, surface waters, or vegetation may or may not be related to CCS project operations.

The Fort Nelson project included efforts to determine baseline conditions of shallow groundwater resources in the vicinity of the c-61-E well location. While it is highly recommended that the baseline conditions for surface waters and soil gas be determined prior to injection operations, the limited site access caused by the Fort Nelson area terrain and climate conditions precluded the collection of such data as part of the feasibility study. Should SET decide to move forward with the CCS project, such baseline data would likely be collected during the design phase of the project.

Fort Nelson Area Surface and Shallow Subsurface Characterization

Surface Characterization Results

The Fort Nelson project is located within the northwestern portion of the Alberta Basin, approximately 25 km southwest of the town of Fort Nelson, British Columbia, Canada, near Alaskan Highway Mile Marker 300. Figure 8 is a map depicting the location of the Fort Nelson project study area. The Fort Nelson study area is largely dominated by boreal forest, which is a complex mosaic of fens, bogs, swamps, and pools and scrubby forest (Royal British Columbia Museum, 2011) and is sparsely populated. The topography is generally flat, with slow-flowing rivers (i.e., the Muskwa, Prophet, and Sikanni Chief Rivers), lakes (most notably Clarke, Milo, and Klowee Lakes), and creeks being the only distinctive features. Regionally, the soil type is poorly drained, silty clay.

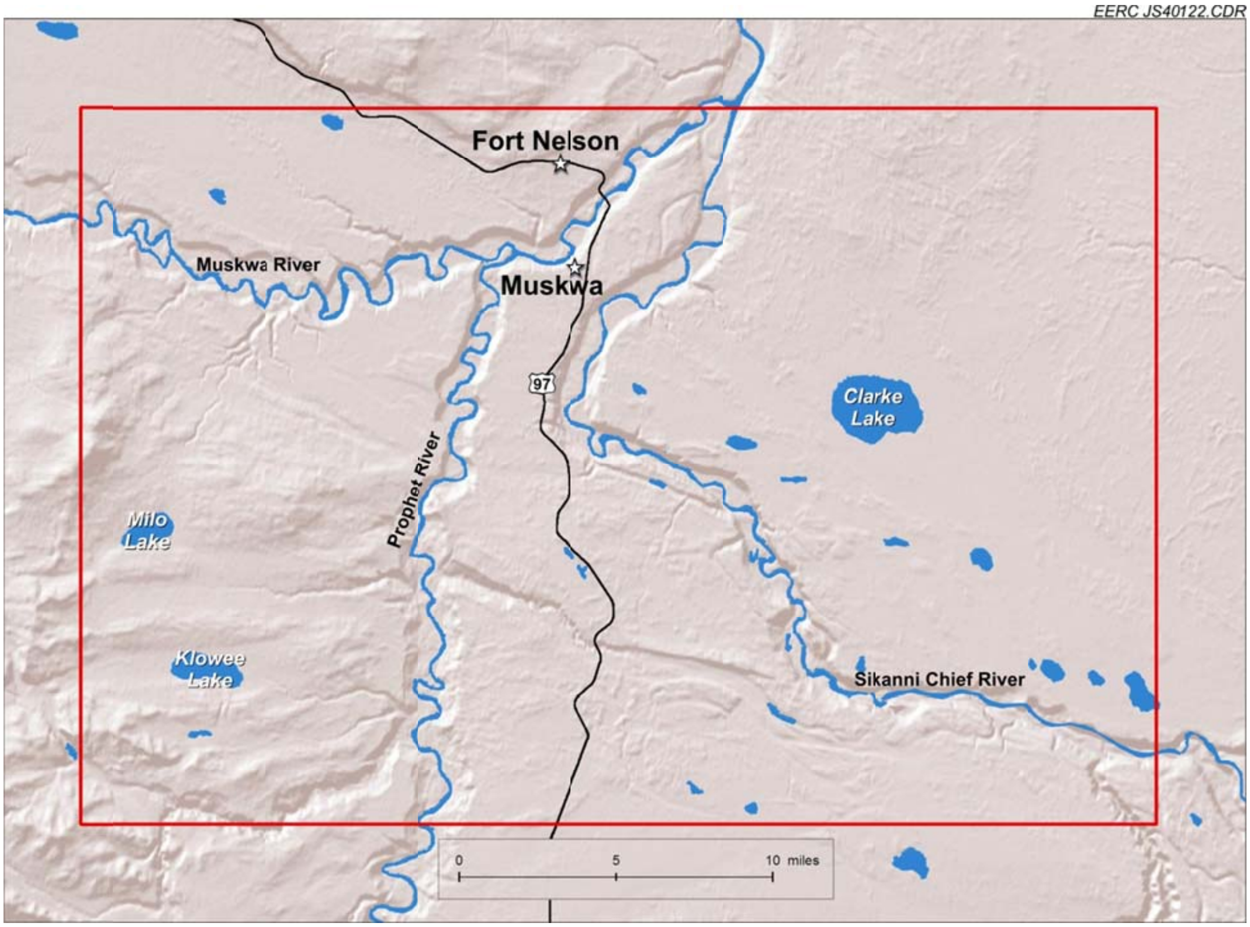

Figure 8. Surface features (lakes, rivers, roads) of the Fort Nelson project study area.

The land in the Fort Nelson area is provincial crown land, owned by the province of British Columbia, Canada. Because of the remote nature of the Fort Nelson area and lack of permanent roads, surface land use activities are limited to hydrocarbon exploration and production as well as trapping, hunting, and fishing. The climate regime of the area is considered to be a muskeg or a taiga “subarctic” plain, having an average mean summer temperature of 12°C, an average mean winter temperature of −15°C, and a mean annual precipitation range of 400–500 mm.

The surface characteristics of the Fort Nelson area exert a significant influence on nearly every aspect of a potential CCS project. The generally flat, forested muskeg terrain combined with fairly high annual precipitation, poorly drained soils, and subarctic climate conditions result in a landscape that is not conducive to the construction of roads. Because of this, most of the Fort Nelson area is accessible only through the use of ice roads or off-road vehicles such as snowmobiles or snowcats in the winter months and helicopters in the nonwinter months. This not only complicates the site selection process, but also limits heavy-duty truck use to a 3- to 4-month period in the winter. Because of these conditions, the logistical aspects of all field-based activities must be planned well in advance. Contingency plans must be ready for activation to take into account any and all complications that might arise as a result of subarctic weather conditions. Drilling, injection, and monitoring activities will all be affected by the surface conditions of the Fort Nelson area. However, it is also important to note that a wide variety of oil and gas exploration and production activities have been conducted in the Fort Nelson area for several decades. While the surface conditions complicate those operations, they have not prevented the gas production industry from thriving in an economically and environmentally sustainable manner. It is expected that the same surface operational strategies and technologies that have been used to develop the Fort Nelson area natural gas resources can be applied to future CCS operations.

Shallow Subsurface Characterization Results

Shallow subsurface characterization has focused primarily on the drilling and subsequent sampling of shallow groundwater wells in the vicinity of SET's deep exploratory well. A sampling and analysis program was conducted using four shallow groundwater wells drilled near the SET CCS Services Inc. Milo c-61-E/94-J-10 (c-61-E) location (Figure 9). All of the wells were used to supply water for drilling operations as well as to supply water for the campsite. The four wells were initially sampled on May 19, 2009, and again on January 20, 2010. The results of those efforts are presented and discussed in the Fort Nelson site characterization report (Sorensen and others, 2014b).

The primary purpose of the groundwater-monitoring wells is to provide baseline data regarding the quality of shallow groundwater resources. These baseline data can then be used as points of comparison for injection and postinjection sampling events to determine what effects, if any, the storage of sour CO_2 may have had on the shallow groundwater. The results from the samples collected in both May 2009 and January 2010 were used to determine baseline parameters for water quality in the area; additional future sampling may be beneficial to document the seasonal variability of these data, if such variability exists. All shallow groundwater parameters were observed to be within ranges that are typical of shallow groundwater in that area of British Columbia (British Columbia Ministry of Environment, 2007; Sorensen and others, 2014b). A continuing water-monitoring program for the duration of the active injection operations and for a yet-to-be-determined postinjection period will need to be implemented once injection has been initiated. However, it is important to note that naturally driven, long-term changes in surface conditions may affect shallow groundwater parameters. Such phenomena may need to be factored into deviations from baseline data, should deviations occur once injection is taking place.

UNDERSTANDING THE STORAGE SYSTEM (SEALS AND SINKS)

Geologic Characterization

The purpose of the baseline geologic characterization activities for any CCS project is to establish the capacity and integrity of the potential sink–seal systems in the project area. These activities are planned and conducted to address questions related to CO_2 injection operations and determine the key characteristics of those systems as they may apply to long-term storage of CO_2. These data will provide the framework for subsequent predictive modeling, RA, and

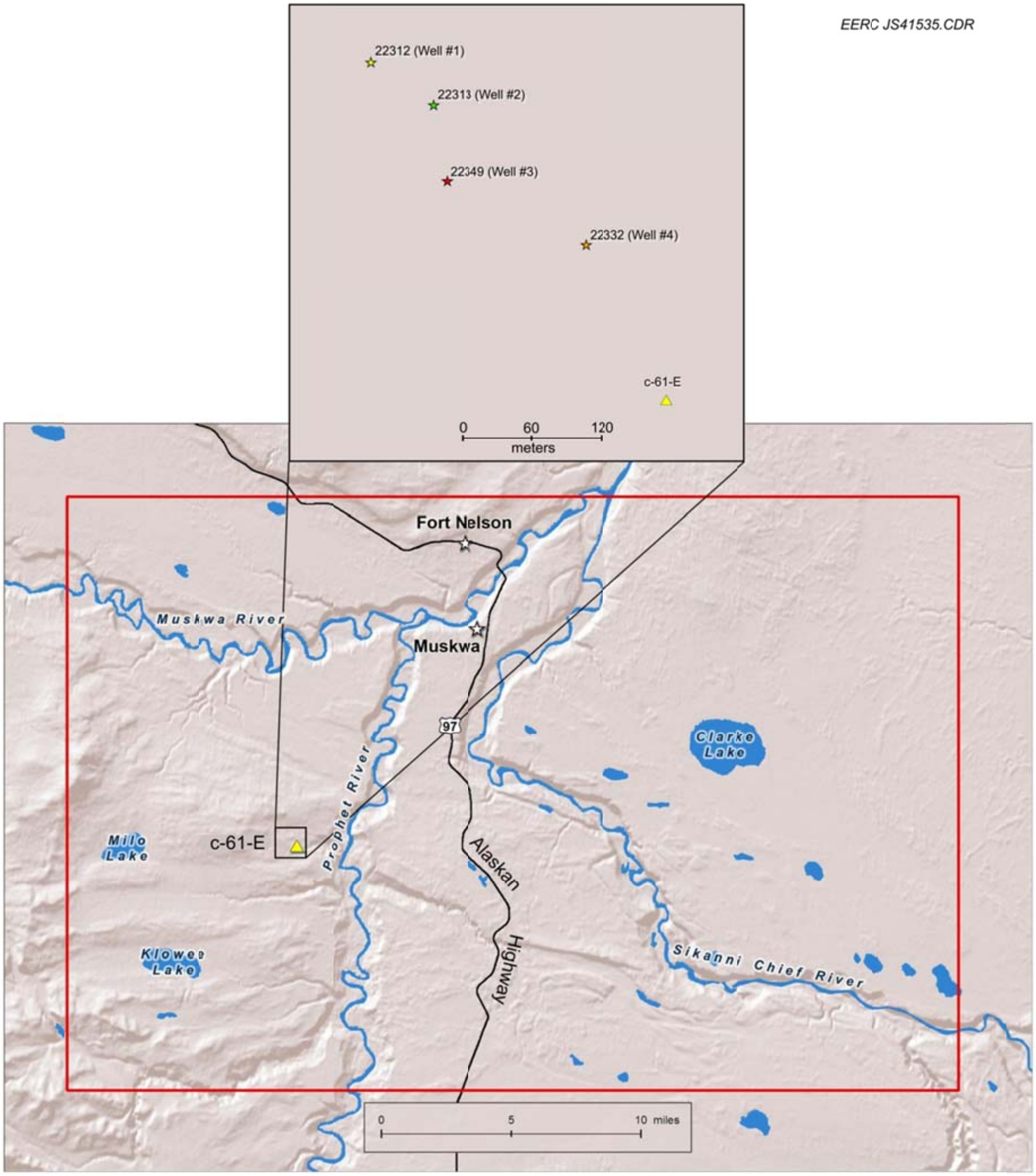

Figure 9. Location of Groundwater Wells 1–4 used in the baseline data collection relative to the exploration well, c-61-E.

monitoring design efforts. The preinjection baseline geologic characterization data also serve as a foundation by which data generated over the course of the later project phases (injection, postinjection, closure) could be compared. In this way, the effects of the CCS project on the geosphere can be effectively determined over the course of the entire operation. The geologic characterization of the Fort Nelson area focused on the surface and shallow subsurface environments, deep injection target formations (sinks) and their associated sealing formations (seals), other formations that may be of interest to project stakeholders (e.g., hydrocarbon-bearing formations, water disposal zones, etc.), and structural features and hydrogeological factors that will control or affect the movement and ultimate fate of the injected sour CO_2. Baseline geologic characterization should include, but not necessarily be limited to, a review of published literature on the area in question, the evaluation of existing geotechnical data (e.g., well logs, seismic data, core and fluid analysis data, etc.), and collection of new, site-specific geotechnical data to fill knowledge gaps.

At any location being considered for long-term CO_2 storage, establishing the capacity and integrity of the sink–seal system can be accomplished by determining the following:

- Geologic structure

- Rock mineralogy and composition of formation water

- Baseline hydrogeology

- Mechanical rock properties and stress regime

- Nature of geochemical interactions between formation and injected fluids and reservoir rock and cap rock

- Nature of wellbore integrity and leakage potential

Key characteristics affecting the long-term mobility and fate of the injected acid gas stream should also be evaluated at different scales:

- Reservoir scale (a few kilometers radius from the injection site)
- Local scale (tens of kilometers radius from the injection site)
- Regional or subbasin scale (hundreds of kilometers radius from the injection site)

As part of the Fort Nelson project, work at the **reservoir scale** focused on an area within a few kilometers radius of what is considered to be a potential injection location, with an emphasis on the key underlying and overlying units that may serve as sinks or seals.

Local-scale characterization efforts in the Fort Nelson area covered an area tens of kilometers in radius from the injection site. Stratigraphically, the entire sedimentary succession from the basement to the surface was evaluated to some extent at the local scale, although emphasis was placed on the potential sink and seal formations.

Work at the **regional**, or **subbasin, scale** (thousands of square kilometers) evaluated relevant data and information on key geologic formations over the northwestern portion of the Alberta Basin. Hydrogeological systems and the regional continuity of primary sealing formations were the focus of studies at this large scale.

Specific geologic characterization efforts for the Fort Nelson project included the following:

- Literature reviews and the examination of regional and local surface maps and aerial photos

- Drilling and testing of a deep exploratory test well (c-61-E) as well as drilling, logging, and injection testing of a sidetrack (d-61-E) of the original deep exploratory test well

- Laboratory-based geochemical, petrophysical, and geomechanical analytical activities using cuttings and core samples from the target formations

- Purchase and interpretation of available historical 2-D and 3-D seismic surveys

- Survey and collection of historical data for existing wells

- In-depth examination of the hydrogeology of the Middle Devonian aquifer system

Each of these geologic characterization efforts provided input into the petrophysical reservoir model of the potential Fort Nelson project site. Specifically, these geologic characterization efforts informed the petrophysical reservoir model by providing information about structure, stratigraphy, formation properties (e.g., porosity, permeability, etc.), faults, and other physical features. The petrophysical reservoir model aids in the understanding and prediction of the behavior of the injected gas over the injection and postinjection periods. The modeling is also a critical tool for determining storage capacity and assessing potential scenarios of leakage to the surface, known natural gas pools, and usable water resources, which are essential inputs to the overall RA.

A summary of the approaches and results of the Fort Nelson geologic characterization efforts is provided as an example of baseline geologic characterization for a deep carbonate saline formation. There are two aspects from which the Fort Nelson project can be considered a good case study for baseline geologic characterization. First, because there is a substantial amount of historical data from hydrocarbon exploration and production activities in the Fort Nelson area, it offers insight into how the data can be evaluated and applied to a CCS project. Second, while there are historical data for the area, its remote location, harsh climate conditions, and difficult terrain mean that there are also underexplored portions of the area for which major data gaps exist. This means that the drilling of an exploratory well and acquisition of new seismic data were an essential part of the baseline characterization program. The knowledge gained from those operations provides stakeholders with insight into approaches and techniques that could be applied to less explored geologic formations, which is often the case with non-hydrocarbon-producing saline formations. More detailed information regarding the Fort Nelson efforts can be found in the PCOR Partnership site characterization report (Sorensen and others, 2014b).

The Geologic Column – Sinks, Seals, and Other Formations

The geologic column is the sequence of uniquely identifiable rock formations that exists at any given location. In the realm of CCS, as with petroleum geology, sedimentary rock formations are most likely to be the formations of interest within the geologic column because of their potential for adequate porosity and permeability to support injection. There are three primary categories of sedimentary rocks relevant to deep geological storage of CO_2, clastics, carbonates, and evaporites. Clastic rocks are principally composed of broken fragments derived from preexisting rocks. Their depositional environments include marine (e.g., shallow to deep ocean) and terrestrial settings (e.g., rivers, lakes, and deserts). Common examples of clastic rocks include sandstones and shales. Carbonate rocks are formed by the organic or inorganic precipitation of carbonate minerals (e.g., calcite and dolomite) and are most often associated with marine environments. Limestones and dolomites are the most commonly occurring carbonate rock formations. Evaporites are composed primarily of minerals produced from saline waters as a result of evaporation. Examples include gypsum, anhydrite, and halite. When considering an area as a potential location for CCS, it is important to have some fundamental knowledge of the properties of each distinct rock unit in that location's geologic column so that suitable sinks and seals can be identified.

Identifying a viable sink–seal system is an essential part of the site selection process for any CCS project. A geologic sink is a rock formation that has adequate porosity, permeability, and storage capacity to support large-scale injection of CO_2 and is separated from USDW by a competent sealing formation. A seal is a low-permeability rock formation that has adequate thickness and geomechanical integrity to prevent the vertical migration of CO_2 over a geologic time frame (thousands of years). With respect to CO_2 storage, clastic and carbonate rocks can serve as either sinks or seals, depending on their porosity and permeability characteristics. Evaporites are typically tight, low-permeability rocks that may serve as seals if they have adequate thickness and lateral extent.

In some cases, formations that are not directly part of the sink–seal system may be affected by large-scale CO_2 injection and storage. If those formations are being used or could be used for any commercial or residential purposes or if they may potentially serve as pathways for CO_2 leakage to the surface, then they must also be characterized at a level that is appropriate to determine their relationship with the sink–seal system.

Potential Sinks and Seals in the Fort Nelson Area

As presented in the literature, the sedimentary succession in the Fort Nelson area consists, in ascending order from the Precambrian crystalline basement to the surface, of Middle and Upper Devonian carbonates, evaporites, and shales; Mississippian carbonates; and Lower Cretaceous shales overlain by Quaternary glacial drift unconsolidated sediments. Figure 3 shows a stratigraphic column of the entire sedimentary succession in the Fort Nelson area, including the relative position of the key rock formations of interest that make up the potential sink–seal system. Figure 10 provides a more detailed look at the stratigraphy of the potential sink–seal system as observed in a gamma ray and lithology logs from SET's exploratory well.

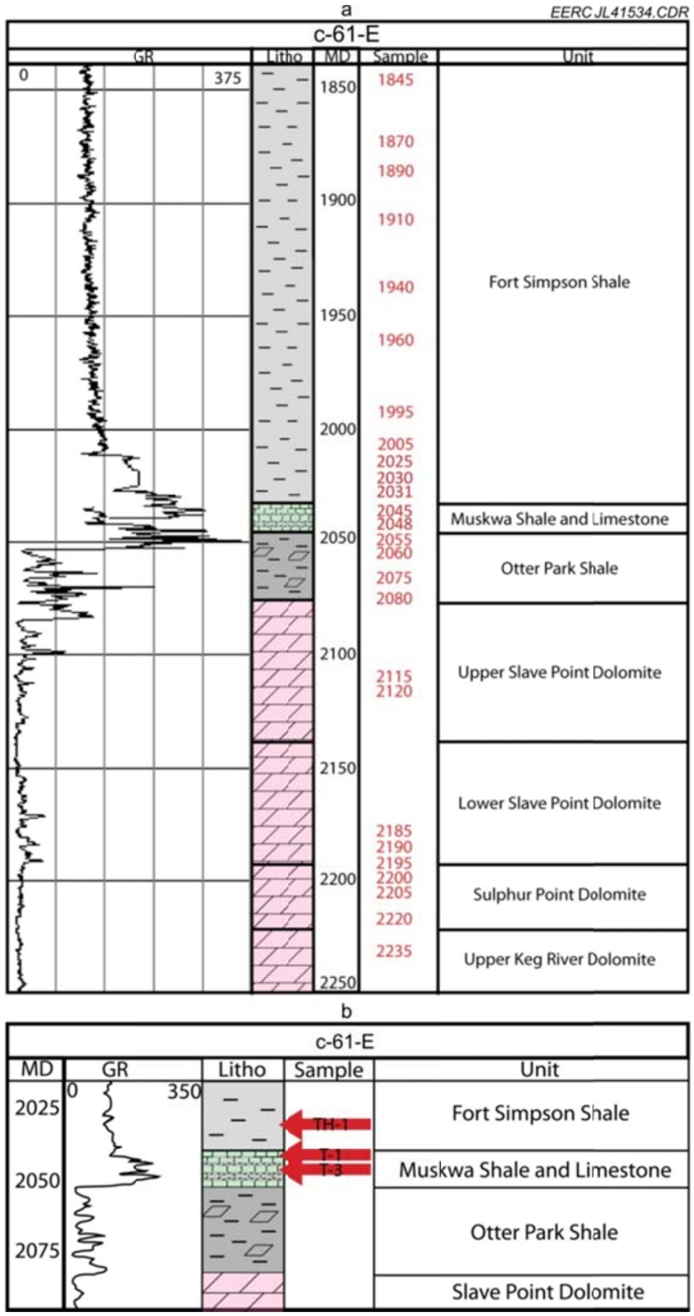

Figure 10. Gamma and lithology logs from Well c-61-E, with marked sample locations a) from the Fort Simpson, Muskwa, Otter Park, Slave Point, Sulphur Point, and Keg River Formations and b) for petrographic analysis from the Fort Simpson and Muskwa Formations (Sorensen and others, 2014b).

With respect to potential sinks, the carbonate platforms and reefs of the Middle Devonian formations that make up the Presqu'ile reef structure in the northern Alberta Basin are known to contain large quantities of hydrocarbons. The presence of hydrocarbons, which have accumulated over millions of years, suggests that the formations have adequate porosity, permeability, and trapping mechanisms to support the long-term storage of large volumes of CO_2 (Sorensen and others, 2005; Bachu and Stewart, 2002). The Fort Nelson project identified three carbonate formations that may be suitable as sinks for commercial-scale CO_2 storage. The information gathered as part of the historical and more recent exploration activities identified the brine-saturated Sulphur Point and Keg River Formations as being the most likely sink formations for the Fort Nelson project. It was also noted that the Slave Point Formation appears to have adequate injectivity and storage capacity to serve as a sink, but the presence of economically recoverable natural gas in the Slave Point in the Fort Nelson area will likely preclude it from being the primary storage target for at least a number of decades. All three of those formations are part of the Devonian Presqu'ile reef complex. Regarding potential primary seals, the Presqu'ile reef complex in the Fort Nelson area is overlain by thick, laterally extensive, low-permeability shales of the Devonian Muskwa and Fort Simpson Formations. Together, these two shale formations represent a formidable cap rock of approximately 550 m in total thickness. Shales and low-permeability carbonate rocks within the Mississippian Banff and the Cretaceous Buckinghorse Formations also serve as laterally extensive barriers to the upward migration of CO_2 and are considered to be secondary seals for any potential Fort Nelson project.

Other Key Formations in the Fort Nelson Geologic Column

Although the sink and seal formations provide the most critical elements of an effective CCS operation (i.e., storage capacity and containment), it is important to note that there may be other rock formations in the project area that may play important roles and, therefore, must also be characterized to some extent. There are anywhere from 20 to 25 distinctly identifiable rock units present in the Fort Nelson area geologic column, depending on any specific given location. Of the rock units that will not serve as either primary sinks or seals, four have been identified as being of importance to the Fort Nelson project. As noted above, the Devonian-age Slave Point Formation in the Fort Nelson area contains natural gas resources that are likely to be productive until at least the mid-2020s, so any CCS operation needs to be designed to avoid contaminating those natural gas pools with sour CO_2. The Watt Mountain Formation is a thin, low-permeability, shaly carbonate that exists discontinuously between the Slave Point and Sulphur Point Formations. The discontinuous nature of the Watt Mountain means that it will likely act as a baffling layer for sour CO_2 that is injected in the underlying Sulphur Point and/or Keg River Formations, impeding, but not entirely containing, its upward migration. The Otter Park Formation represents the uppermost part of the Presqu'ile reef complex, and while its permeability is too low for it to be considered a potential sink and its mechanical integrity is too low to be considered a competent seal, it does need to be taken into account when predicting the long-term movement and fate of injected sour CO_2. The Mississippian-age Debolt Formation is the first major porous and permeable zone above the primary seals. As such, it should be monitored for any signs of sour CO_2 migration out of zone. It is also used by the gas production industry as a produced water disposal zone and as a source of industrial use-quality water for drilling and completion operations in the nearby Horn River shale gas play. As with the Slave Point Formation, CCS injection activities need to be designed to avoid impacting any operations in the Debolt Formation; therefore, understanding its geologic and hydrogeologic characteristics is critical.

Historical (pre-2009) Sources of Geologic Characterization Data

Examining historical characterization data sets from oil, gas, and mineral exploration efforts is an essential first step in evaluating an area for potential CCS operations. Well files are the backbone of historical data and can be obtained from government regulatory agencies, commercial vendors, or both. Well files typically include geophysical logs, core and fluid analysis data, drilling reports, well-testing results, and reservoir fluid production and/or fluid injection data, the sum total of which provide a wealth of information on reservoir properties. Other readily available historical data can be found in published journal articles, technical conference proceedings, geological survey reports, and academic publications such as Ph.D. dissertations and masters theses. Less readily available data sources include unpublished, specialized technical reports either commissioned or prepared in-house by exploration and production companies. Historical seismic data are typically only available through lease or purchase from a vendor or operating company and often must be processed for interpretation. As such, their use can be expensive and time-consuming, but the detailed 2-D and/or 3-D views that they provide of the geologic setting can be invaluable, especially with respect to identifying structural features and the distribution of some formation properties (e.g., porosity). Permit applications to relevant regulatory authorities for drilling, production, and/or injection operations are also often good sources of key data, including reservoir property summaries, maps, and detailed descriptions of previous operations in the area. All of these types of historical data sets were sought, obtained when available, and applied to the Fort Nelson geologic characterization efforts.

Exploration activities for mineral and energy resources in western Canada over the last 50 years have yielded a significant amount of information about the geology of northeastern British Columbia and northwestern Alberta. Data sets associated with the exploration activities in the Fort Nelson area include wireline well logs and production and/or injection data from nearly 100 wells. Many wells in the area also include core and fluid analysis data and the results of reservoir-testing activities. These data sets provide quantitative information on key formation parameters such as depth, thickness, lithology, porosity, permeability, and structure. Examination and evaluation of these historical data sets indicate that the Devonian-age reef system that underlies much of the Fort Nelson area may be capable of providing a sink–seal system that is world-class in terms of injectivity, storage capacity, and containment.

Recent (2009–2012) Deep Subsurface Characterization Data

While there are enough historical data to identify areas in the Fort Nelson area that have good potential for hosting a CCS project, to avoid interfering with existing hydrocarbon production operations, it was necessary to focus the site selection efforts on areas with few wells. Unfortunately, areas with fewer wells will have more data gaps. To begin filling those data gaps, SET and the EERC conducted a number of new geologic characterization activities as part of the Fort Nelson project. As of January 2012, SET and the EERC had completed numerous efforts, including field- and laboratory-based activities, modeling exercises, and historical database investigations to identify and evaluate the sink–seal systems and other formations in the Fort Nelson area. These efforts generated previously unavailable data and valuable new insight regarding the geologic properties of those formations. As previously noted, these characterization activities included acquisition of well files, purchase and interpretation of historical 2-D and 3-D seismic surveys (Figure 11), drilling and testing a deep exploratory well (c-61-E) in 2009, and drilling and testing a sidetrack hole (d-61-E) off of the vertical c-61-E well in 2010. Laboratory-based analytical activities using cuttings and core samples were also conducted.

In April 2009, the c-61-E well was drilled down into the carbonate barrier reef complex, penetrating the Chinchaga Formation and reaching a total depth of 2561 m. In December 2009, the c-61-E well was reentered and a second borehole (designated d-61-E and referred to as the "sidetrack" wellbore) drilled at an angle of approximately 30 degrees away from the previously existing vertical borehole. The sidetrack wellbore extended from the approximate middle of the Slave Point Formation and ended at a depth of 2282 m in either the Lower Sulphur Point Formation or the Upper Keg River Formation. Figure 6 illustrates the location of the c-61-E test well in relation to key site features.

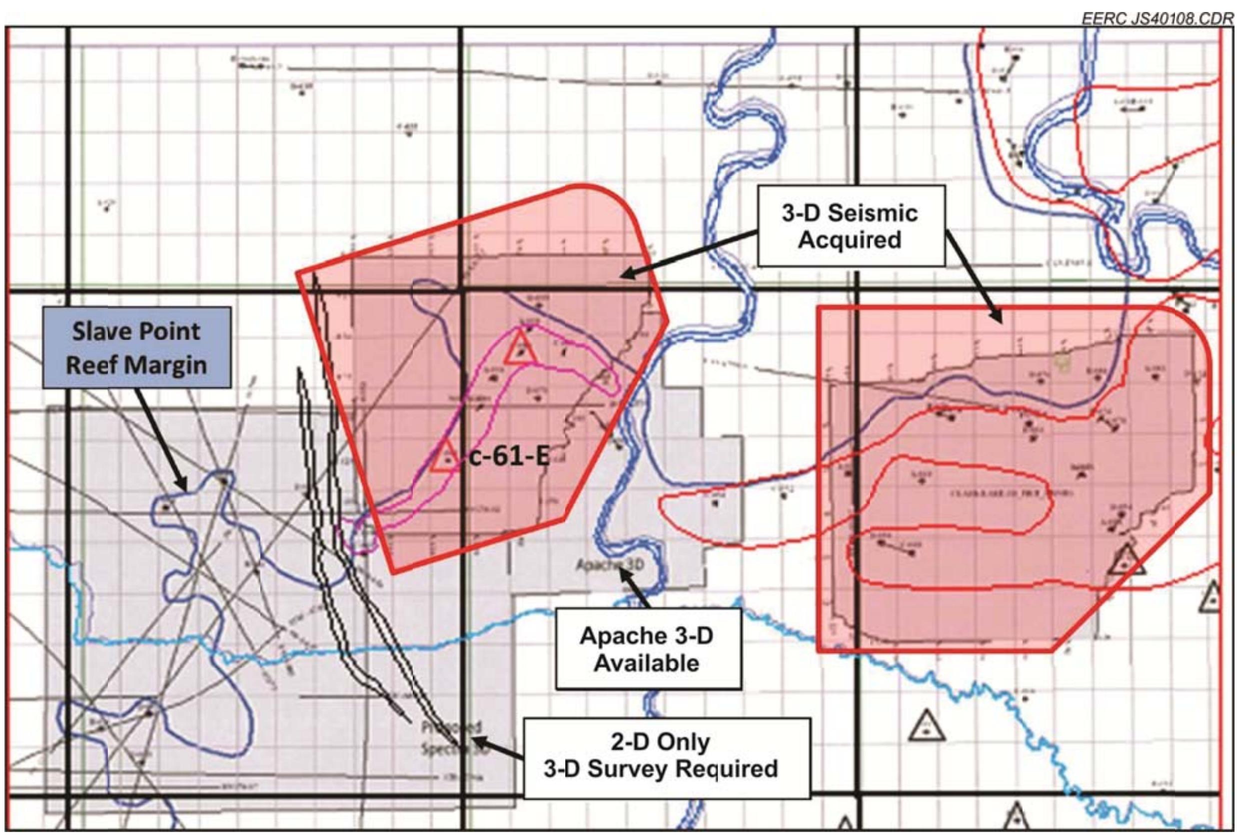

Figure 11. Acquired and available seismic survey locations within the Fort Nelson study area (Sorensen and others, 2014b).

Specific characterization activities in the two boreholes (c-61-E and d-61-E) of the Fort Nelson exploratory well included the running of openhole and cased-hole well logs, the collection of core, and injection-related tests. The suite of well logs that were run through most of the Devonian portion of the wellbore included gamma ray, neutron porosity, lithodensity, cement bond logs, and spontaneous potential/induction logs. Sonic and formation microimaging (FMI) logs were also run in the Presqu'ile reef portion of the well. Three types of injection tests were conducted on the Slave Point, Sulphur Point, and Keg River Formations: 1) a leakoff test to determine the strength or fracture pressure of the open formation, 2) two separate water injection tests to assess the ability of the formations to accept fluids, and 3) a commingled water injection test.

The primary goal of these drilling and testing programs was to determine the fundamental geologic characteristics of the seal–sink system, particularly with respect to injectivity, storage capacity, and integrity of containment in the Fort Nelson project area. The results of these characterization activities are presented and discussed in greater detail later in this report. A full accounting of these activities and the data generated by them can be found in Sorensen and others (2014b).

Geologic Structural Elements

Geologic structure is defined as the general disposition, attitude, arrangement, or relative positions of the rock masses of a region or area (Bates and Jackson, 1987). Many of the more common structural features are the consequence of postdepositional deformational processes such as the faulting, fracturing, and folding of formations that are typically associated with large-scale tectonic events (e.g., mountain building and basin subsidence). Other structural features can be the result of a depositional environment that allows the formation of rock units with their own distinctive 3-D geometry, such as reefs in carbonate systems, sand bars in clastic systems, and dunes in aeolian systems. In petroleum geology, structure is considered to be any physical arrangement of rocks that may hold an accumulation of oil or gas. This aspect also applies to CO_2 injection and storage, making the detailed determination of structure a critical component of any baseline geologic characterization efforts. Understanding the geologic structure elements of an area is crucial to predicting the movement and ultimate containment of the CO_2 plume and the nature of pressure propagation through the sink–seal system.

Structural elements of the Fort Nelson area include the 3-D geometry of the reef complex, faults, fractures, and hydrothermal sag features. The strike, dip, and surface relief of formations and the strike and dip of faults and fractures are particularly crucial to accurately predict the movement of buoyant fluids such as sour CO_2. These elements can be identified and incorporated into a static geologic model using data from well logs, seismic surveys, and the analysis of core and cuttings.

The current understanding of the structural elements of the Fort Nelson project area is based on the synthesis and evaluation of historical 2-D and 3-D seismic survey data (Figure 11), well log data from a total of 96 wells (29 of which penetrate the Sulphur Point Formation) (Figure 12), test well information, all drillstem test (DST) information available within the project study area, cross sections, and review of facies determinations from core, cuttings, and well logs.

Based on this information and utilizing a barrier reef depositional environment as the overall framework for the system, structure maps were developed for the top of each formation in the reef from the top of the Fort Simpson shale to the Chinchaga Formation. Other structural features that were identified included the presence of hydrothermal sags (localized downwarping of beds caused by the intrusion of hydrothermal fluids) and a fault–graben system that cuts in a north–south-trending direction across the reef front approximately 1 km west of c-61-E (Sorensen and others, 2014b). Figure 13 presents a structure map for the top of the Sulphur Point Formation in the vicinity of c-61-E in which hydrothermal sags and the fault–graben system can be clearly identified.

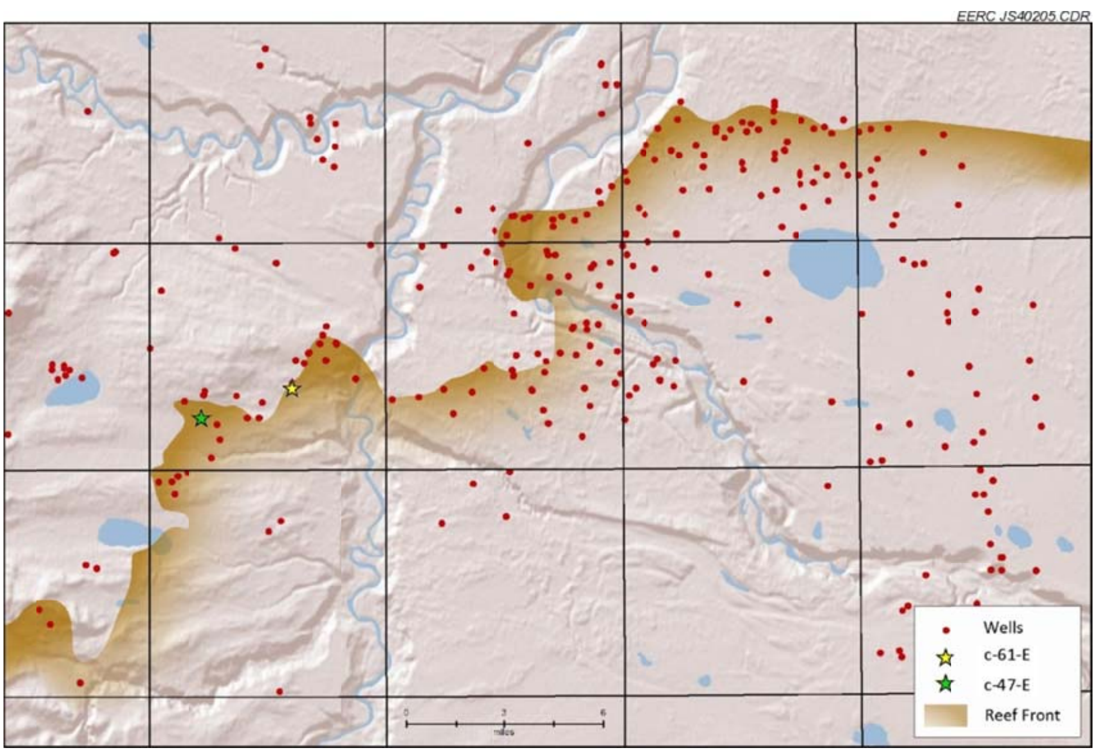

Figure 12. Location of 96 wells for which well log data were available (Sorensen and others, 2014b).

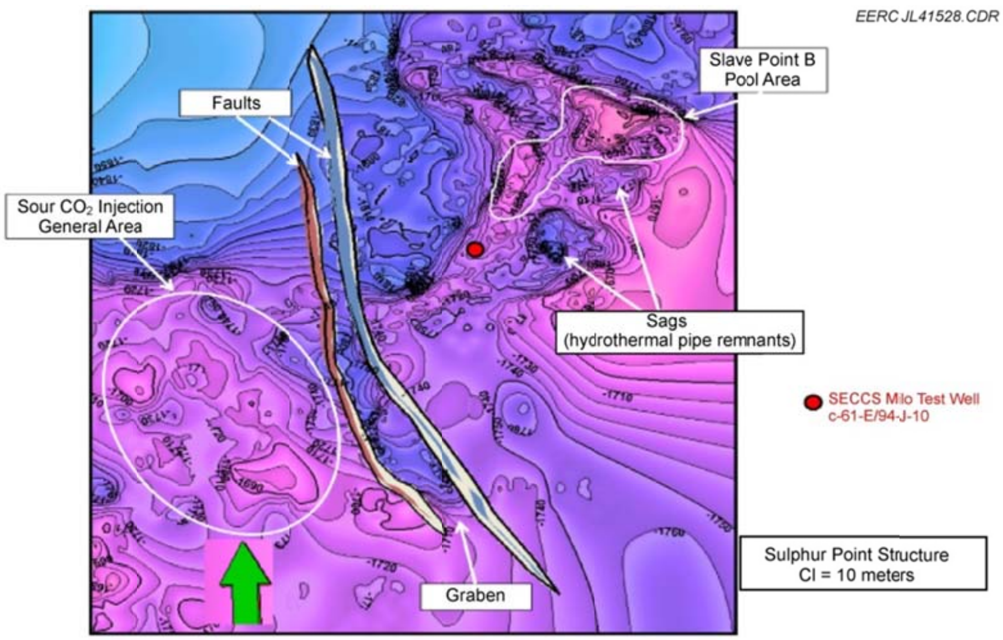

Figure 13. Structure map of the top of the Sulphur Point Formation in the vicinity of the c-61-E well (Sorensen and others, 2014b). The area marked "Sour CO_2 Injection General Area" is for the proposed potential injection location at c-47-E. The existing location at c-61-E is denoted by the red circle.

The structural interpretations for the reef were integrated along with porosity and permeability distribution interpretations to create static geologic models for the Fort Nelson project area. Figure 14 shows a cross-sectional example from west to east taken from the base case version of the static model. This cross section illustrates the structural complexity that exists within the Presqu'ile reef complex in the Fort Nelson area. Within the cross section, the fault–graben system and at least two sag features can be clearly identified. It is important to keep in mind that the properties of the rock units and structural elements within the static models are populated in three dimensions, and any given vertical cross section will reveal different aspects of the stratigraphy and structural features. It is also important to bear in mind that the precise locations of features and distribution of rock properties are largely based on the interpretations of a team of geologists, geophysicists, and reservoir engineers, and such interpretations inherently include a degree of uncertainty. Relative to a commercially operated oil or gas field, the amount of seismic and well-based data available for the Fort Nelson project area is limited, and the level of uncertainty associated with the interpretations that form the current understanding of the Fort Nelson sink–seal system is, therefore, relatively high. The acquisition of additional data is necessary to reduce the uncertainty associated with the current knowledge of the Presqu'ile reef in the Fort Nelson area.

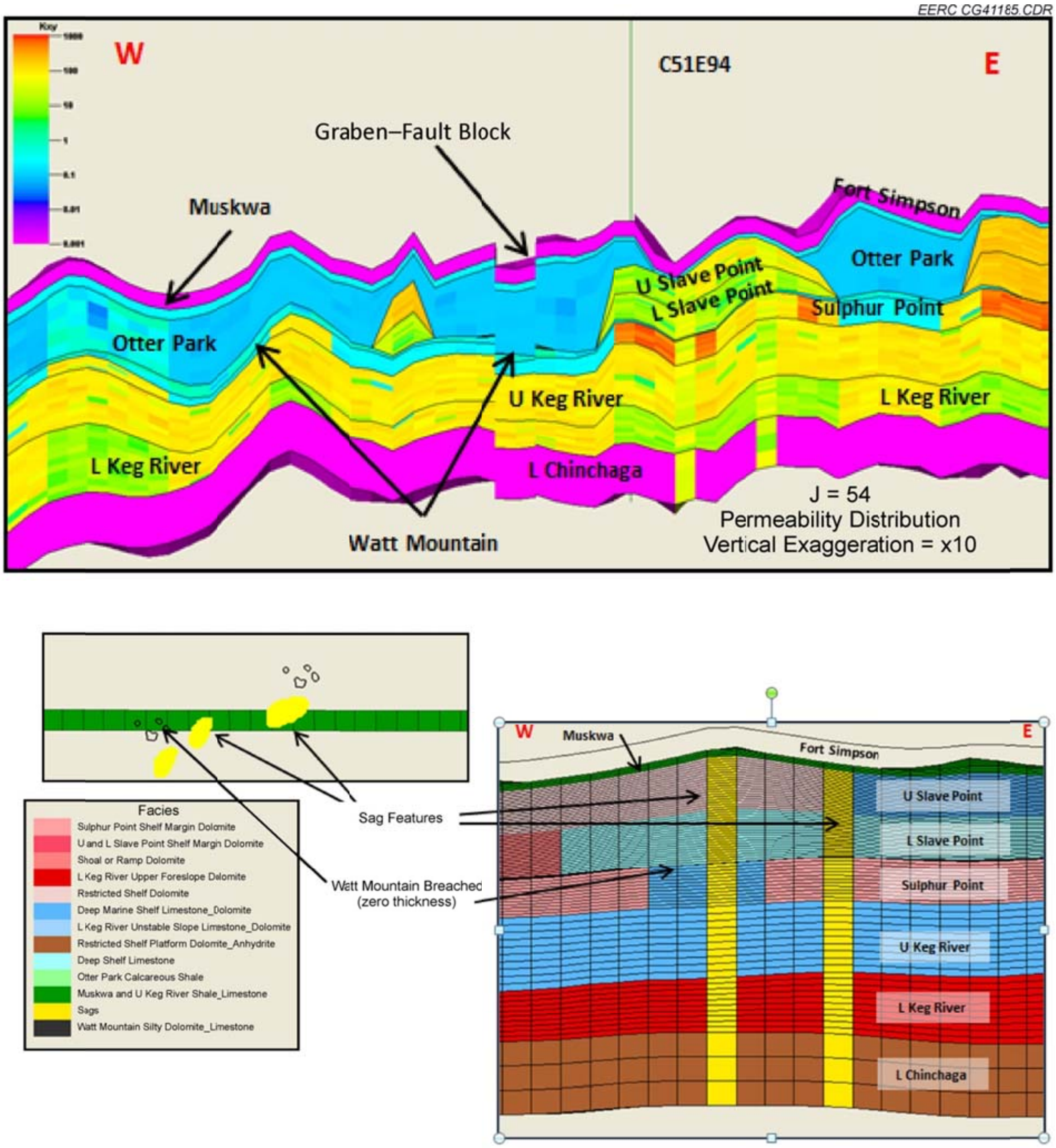

Figure 14. Fort Nelson project static model cross section (Sorensen and others, 2014b).

Based on the available geophysical and seismic data, 13 domains and ten zones were identified. Domains were based on zones of consistent rock properties that may relate to a depositional setting or structural feature. In some cases, a domain may cross formation boundaries (e.g., Upper Chinchaga and Lower Keg River). The formation intervals that were included in the 13 domains are the Fort Simpson, Muskwa, Otter Park, Upper and Lower Slave Point, Watt Mountain, Sulphur Point, Upper and Lower Keg River, and Upper and Lower Chinchaga Formations (Figure 15).

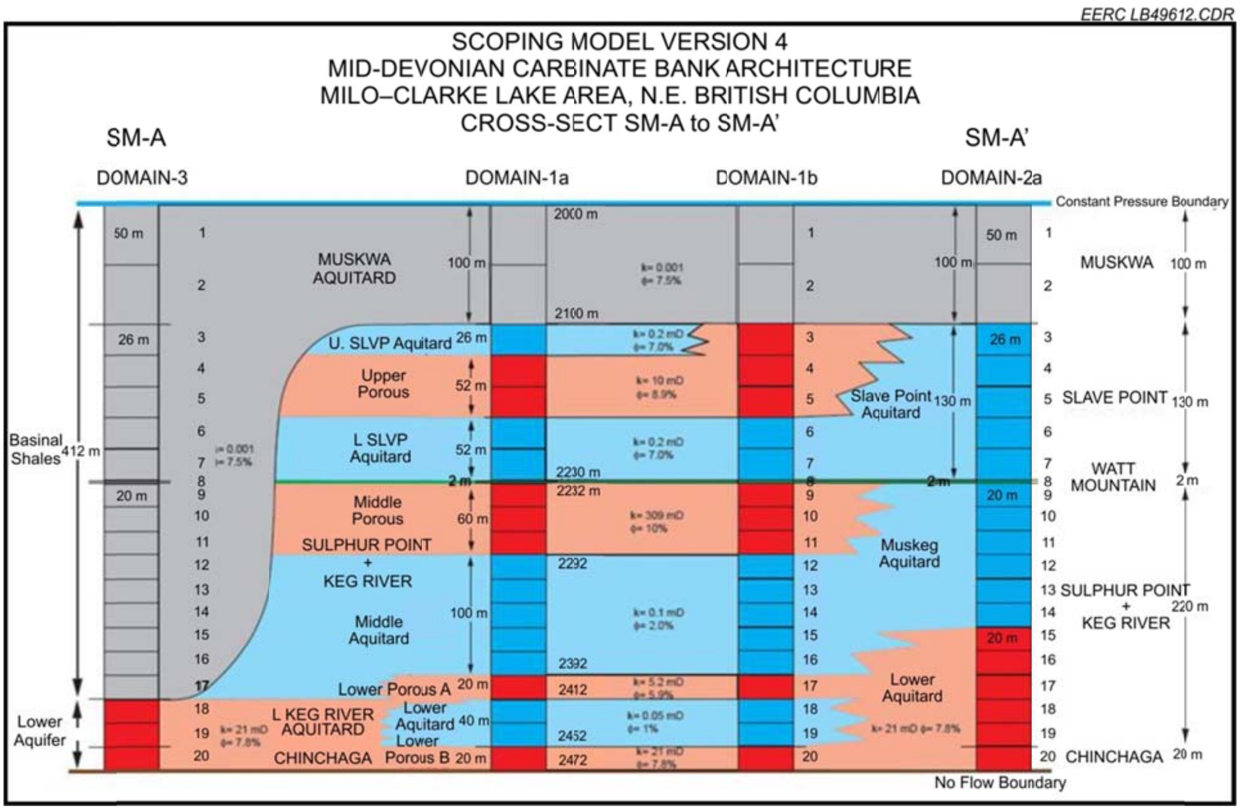

Figure 15. Properties of the model-populated domain and zones at the Fort Nelson project site (Sorensen and others, 2014b).

SINK AND SEAL CHARACTERIZATION APPROACHES AND TECHNIQUES

The rock properties of potential sink–seal systems must be thoroughly quantified to demonstrate their ability to store CO_2. For potential sinks, it is imperative to generate data that provide evidence for determining injectivity and geomechanical integrity thresholds to guide injection operation design as well as data to support estimates of storage capacity. For potential seals, it is critical to determine the ability of the rock to serve as a barrier to vertical migration and contain the injected CO_2 under the anticipated reservoir conditions. It is good practice to conduct a variety of analyses to determine the chemical and physical characteristics of the rocks. Data from a variety of analyses can be used to cross-check and correlate findings and provide illustrations and explanations of results. Characterization of potential sink and sealing rocks should include, but not necessarily be limited to, petrographic assessments, geomechanical property testing, permeability determinations, and evaluation of pore network geometry. Specific approaches and techniques to determine rock properties are briefly described below to provide the reader with background knowledge regarding their application to characterization of rocks at a potential CCS site. These techniques are applicable to samples of both potential sink and seal rocks. The results of the Fort Nelson characterization activities are subsequently presented in terms of the characterization of the seals, followed by the characterization of the sinks.

Petrographic Assessment of Sink–Seal Rocks

A petrographic assessment of sink and seal formations should provide data on geochemical stability, mineralogy, and rock properties pertinent to CO_2 storage and containment. Petrographic analysis involves photographing the rock samples as-received, creation and description of thin sections, identification and estimation of mineral assemblages, mineral cement identification, description of microstructure, and assignment and classification of petrographic energy environment and depositional environment. Specific elements of petrographic assessments may include the following:

- X-ray diffraction (XRD) for bulk mineralogy
- X-ray fluorescence (XRF) for trace element analysis
- Petrographic analysis via thin section for mineralogy and rock fabric descriptions
- Quantitative evaluation of minerals by scanning electron microscopy (SEM) for mineralogical mapping
- SEM with energy-dispersive spectrometry (SEM–EDS) for mineralogical identification and rock fabric descriptions
- Carbon, hydrogen, nitrogen/sulfur (CHN/S) measurements for elemental composition information
- Grain surface area to determine reactive surface
- Skeletal grain density to support mineralogy and examination of total-versus-effective porosity
- Degree of cementation
- Inductively coupled plasma–mass spectroscopy (ICP–MS) to examine trace element abundance

Geomechanical Testing of Sink–Seal Rocks

Geomechanical laboratory tests of core samples are used to establish the geomechanical properties of the rock as well as the stress regime in the planned injection area. These test results provide the basis for assessing the mechanical integrity of the system and an evaluation of the potential for rock fracturing during CO_2 injection operations. Sets of 1.5-inch-diameter core samples representing the sink and seal rocks should be tested for bulk density, acoustic velocity, uniaxial strength, and triaxial strength. Peak strength (at failure) and elastic properties that should be measured will include, but are not necessarily limited to, confining stress at failure, peak strength, Young's modulus, Poisson's ratio, bulk modulus, and shear modulus.

Selected samples may also be tested for residual friction measurements. In these investigations, samples are fitted with strain gauges at 90° intervals around the core to measure the deformation observed under load. The tests are tailored to find parameters for several common failure criteria. These criteria are then used to predict the stress state at which failure would occur in rock. Further, the predicted values aid in determining the pore pressure buildup that can be sustained by rock without failure. The parameters for Hoek–Brown and Mohr–Coulomb criteria may also be found in the study. A brief description of these criteria follows.

The Hoek–Brown criterion is an empirical 2-D criterion that sets limitations on major and minor principal stresses. The criterion is given by the following relationship:

$$\sigma_1 = \sigma_3 + \sqrt{m\sigma_c\sigma_3 + s\sigma_c^2} \qquad \text{[Eq. 1]}$$

Where σ_1 and σ_3 are major and minor principal stresses, σ_c is the uniaxial compressive strength of the rock, and *m* and *s* are constants. Stresses σ_1 and σ_3 are defined by the pressure of overburden and tectonic forces, while σ_c and constants *m* and *s* are determined in laboratory tests.

The Mohr–Coulomb criterion also sets limitations on σ_1 and σ_3 by utilizing the concept of cohesion c and the angle of internal friction ϕ. It is given by the following formula:

$$\sigma_1 - \sigma_3 = \frac{2(c + \mu\sigma_3)}{\sqrt{\mu^2 + 1} + \mu} \qquad \text{[Eq. 2]}$$

Here, $\mu = \tan\phi$ is the coefficient of friction.

Other parameters, such as uniaxial tensile strength, may also be obtained in case the use of additional failure criteria is desirable. These parameters are derived in the laboratory tests at the moment when failure of the tested sample occurs. Techniques specifically measuring the acoustic wave amplitude may be employed to determine the beginning of the sample degradation process. Potentially, these data can be used for setting limiting conditions for injection operations to prevent excessive pressure buildup in the reservoir.

To determine the nature of the stress regime in the sink–seal system, Criteria 1 and 2 provide useful estimates in cases where the stress tensor is known. However, stress tensor can be measured only at discrete points within the system. Alternatively, it can be estimated analytically. Both measured and analytically estimated stresses will vary significantly within the structure. Depending on the shape of the zone of porosity, which in the case of Fort Nelson is a reef, the existence of areas of stress concentrations may be possible. These areas are most susceptible to failure. To check for the possibility of the existence of such areas, numerical modeling accounting for the geometry of the system can be run. Calculating stresses at different points within the system requires knowledge of elastic properties of rock, as described by Young's modulus and Poisson's ratio. Thus tests to derive these parameters should be conducted. The tests will assess two values of the parameters: one that is distinct in a static process (a process with no or slow development in time) and one that is distinct in the case of dynamic processes (a fast-developing process, e.g., fracturing of rock by excessive pressure buildup due to injection or an earthquake). These data can also be used for geophysical log calibration and have potential implications to MVA designs. The results of these geomechanical core analyses will provide a basis for developing accurate models that can be used to predict the effects that large-scale CO_2 injection can have on sink–seal system rocks.

In total, the geomechancial test results will help guide CO_2 injection operations. For example, the cap rock integrity testing and relative permeability data will be used to estimate constraints on maximum injection, which will affect both pipeline and compressor design, set the operational pressures for the system, provide a basis for estimating the risk of fracture propagation, and evaluate potential risk of injectivity loss. Ultimately, for conceptual understanding and forecasting purposes, these laboratory data will be incorporated into a series of multistage, case-specific, uncoupled and coupled 3-D dynamic numerical reservoir geomechanical models.

Permeability Testing

Quantifying permeability is critical to determine the injectivity and capacity of sink formations and the containment integrity of a sealing formation. Permeability can be determined through core studies conducted on core segments (some tests require full-diameter [10-cm] core, and others require smaller-diameter core plugs) taken from dense nonfractured intervals of cores. Tests can be conducted using air, but permeability testing using reservoir fluids or simulated reservoir fluids should be conducted whenever possible to generate data that most accurately represent the condition of the rocks in situ. To be considered a competent cap rock, the effective permeability of the core to formation water should be less than 1×10^{-3} mD, and it should be able to resist CO_2 intrusion at a differential pressure, i.e., a threshold intrusion pressure (TIP), of up to 7000 kilopascals (kPa). Permeability is necessary to conduct dynamic simulation modeling of CO_2 injection and plume/pressure front movement.

Pore Network Geometry Determinations

The interconnected pore system and the size distribution of pore apertures (capillaries), which strongly influence saturations and fluid flow (permeability), can be quantified in a rock sample by mercury injection capillary pressure (MICP) tests, which determine the pore-size distribution, size classification, and a permeability distribution of samples tested. These data provide direct inputs for the determination of threshold, or breakthrough, pressure testing. Such data provide valuable inputs for dynamic simulation modeling of injection operations and plume movement.

Relative Permeability Testing

Relative permeability is a measurement of flow rates of specific fluids that are undergoing two-phase flow. While single-phase permeability is a relatively simple measurement of flow under operational conditions, two-phase flow presents a complex relationship dependent on saturation, wettability, surface tension, and force. Relative permeability tests describe two-phase flow of two fluids relative to 100% brine-saturated flow. For CCS projects in saline formations, relative permeability generally refers to permeability of brine as compared to permeability of supercritical CO_2. In the case of Fort Nelson, the relative permeability testing was based on supercritical CO_2–H_2S and brine. The resulting curve of relative permeability against saturation is required for many flow simulations, but is also indicative of injectivity, identifies reducible water saturation, and estimates reservoir capacity and values for interfacial tension.

FORT NELSON CHARACTERIZATION ACTIVITIES AND RESULTS

The rock characterization approaches and techniques described above were applied to rock samples collected during the drilling of the c-61-E exploratory well. A summary overview of the key results of those activities is presented below in terms of potential seals and sinks for geological storage of sour CO_2 at Fort Nelson. A more detailed presentation of Fort Nelson characterization activities and results, including the data sets upon which the summarized observations and conclusions are based, can be found in Sorensen and others (2014b).

Fort Nelson Seal Characterization

The Fort Simpson Formation is considered to be the primary seal preventing vertical migration of injected sour CO_2 at the Fort Nelson project (Figures 3 and 10). The Muskwa Formation, which immediately underlies the Fort Simpson, is also a low-permeability formation that will serve as a barrier to upward migration of sour CO_2. Together, the Fort Simpson and Muskwa Formations represent a thick, competent, geographically widespread cap rock of approximately 550 m of total thickness in the Fort Nelson area. To evaluate the characteristics of the primary sealing formations, SET ran a suite of well logs in the c-61-E exploratory well and cored part of the Fort Simpson and Muskwa shales. Core and cutting samples were used to conduct a suite of analytical studies to evaluate the mineralogical, geochemical, and geomechanical properties of the seals (Sorensen and others, 2014b, Appendixes A and B).

A petrographic assessment was performed on samples from three intervals of the Fort Simpson and Muskwa Formations. These samples were designated as TH-1, T-1, and T-3, and their specific locations within the wellbore are presented in Figure 10. All three specimens represent various tight cap rock characteristics ideal for the Fort Nelson site, including such features as tight assemblages of stable minerals with low porosity, low permeability, and small pore throat diameter. The first two intervals (TH-1 and T-1) were very similar, containing high percentages of clay, with variable pyrite, silt, and fine-grained carbonate, while the third interval (T-3) contained a much higher degree of sparry carbonate growth. No microstructure was visible in any of the sections. The petrographic properties of the Fort Simpson and Muskwa Formations indicate that they will provide a significant barrier to CO_2 vertical migration. The complete details of this petrographic analysis can be found in the Fort Nelson site characterization report (Sorensen and others, 2014b, Appendix A).

To examine the cap rock integrity at the Fort Nelson site, core studies were conducted on full-diameter core segments taken from dense, nonfractured intervals of cores removed from the Fort Simpson (CR-1A) and Muskwa (CR-2A) shales. A study of the primary sealing formation was conducted using material from Well c-61-E. The objective of this study was to evaluate the competency of the primary seals (Fort Simpson and Muskwa Formations), including pore-size distribution and capillary pressure characteristics using the MICP method. Mechanical property testing to evaluate the integrity of the cap rock was performed as well as analyses of routine petrophysical parameters taken from full-diameter core samples. The complete report on these studies can be found in the Fort Nelson site characterization report (Sorensen and others, 2014b, Appendix B).

The structural integrity and leak resistance investigations of the Fort Nelson cap rocks showed that each of the formations was found to be completely impermeable to sour CO_2 at injection pressures of more than 10,000 kPa and exhibited effective permeabilities to sour CO_2-saturated brine of 4.6×10^{-6} mD (Fort Simpson) and 9×10^{-7} mD (Muskwa) at injection pressures of 5500 kPa. Both of these values are many orders of magnitude less than the commonly accepted maximum permeability of cap rocks to fluid of 1×10^{-3} mD, indicating these rocks will serve as excellent seals.

MICP testing was completed on samples of the Fort Simpson and Muskwa Formations. Based on these tests, both the Fort Simpson and Muskwa Formations were characterized as having a pore throat type of 100% micropores (pore diameter of less than 1 μm). The MICP testing also yielded a TIP of 24,790 kPa for each of the formations, three times greater than the minimum acceptable TIP of 7000 kPa, which further supports the conclusion that these formations are competent seals for a large-scale CO_2 storage operation. The Otter Park shale sequence was also tested to determine if it could be considered a seal. Like the Fort Simpson and Muskwa, it also consisted of 100% micropores but had a TIP of 6480 kPa, which is below the minimum acceptable value for a seal and, therefore, precludes it from being considered an effective seal.

Samples of the Muskwa Formation (2045 m) were evaluated for mechanical properties. Specifically, triaxial compressive strength and dynamic elastic parameters were determined using two representative plugs, MP1 and MP2, which were collected 0.14 m apart. The average compressive strength of these Muskwa shale samples was determined to be 202,750 kPa, which is ten times higher than the expected Fort Nelson project operating pressures (~20 kPa).

The results of the petrographic analysis of the Fort Nelson seal formations combined with the core test studies provided compelling evidence that the thick shales of the Fort Simpson and

Muskwa Formations will serve as a competent vertical seal for the injection and long-term storage of sour CO_2. However, further testing and characterization of the Muskwa and Fort Simpson Formations must be done at a larger scale to determine the presence and condition of fractures and faults that may exist in those formations in the Fort Nelson area.

Fort Nelson Sink Characterization

The Sulphur Point Formation and the Upper Keg River Formation, which immediately underlies the Sulphur Point, appear to have properties that will allow them to serve as primary sink targets for long-term sour CO_2 storage. Together, these formations represent a package of rock that appears to have sufficient porosity, permeability, and lateral continuity to serve as zones for large-scale injection and storage of sour CO_2 in the Fort Nelson area. Core samples were collected from Well c-61-E representing the following sink formation intervals: 2129–2143 m (Upper and Lower Slave Point Formation) and 2362–2387 m (Lower Keg River Formation). The original coring program was intended to capture core from both the various shale cap rock sequences as well as the highly porous and permeable sections of the c-61-E well that had previously been identified as candidates for CO_2 storage. However, the very heterogeneous, vuggy character of the Sulphur Point and Slave Point Formations precluded securing representative cores from these potential sink formations. The core samples were used to create core plugs and thin sections that were used in the various sink formation assessment and testing activities to evaluate the mineralogical, geochemical, and permeability properties of the potential sinks. SET also ran a suite of well logs that were used to correlate laboratory data to log characteristics.

Specific laboratory analyses that were conducted on the potential Fort Nelson sink formation rock samples included XRD, XRF, QEM (quantitative evaluation of minerals) SEM, and SEM–EDS for mineralogical and geochemical evaluations (Sorensen and others, 2014c, Appendix A). Laboratory-based permeability and relative permeability testing was performed on only three core samples (REL K-1 and REL K-2 from the Lower Slave Point Formation and REL K-3 from the Lower Keg River Formation). A more detailed presentation of that testing is provided in Sorensen and others (2014b), Appendix B. However, once it had been recognized from the routine core permeability measurements that the Lower Keg River represented a nonreservoir rock, the relative permeability testing on this sample was terminated, leaving only test data for the two core samples, REL K-1 and REL K-2, from the Lower Slave Point Formation. Because the gas stream from FNGP will likely include a small amount of H_2S, the relative permeability testing was conducted using sour CO_2 (i.e., a mixture of 95% CO_2 and 5% H_2S). The relative permeability curves generated by those tests are presented in Sorensen and others (2014b), Appendix B. The relative permeability measurements conducted on these two core samples suggest that the processes of sour CO_2 displacing brine and brine displacing sour CO_2 are equally efficient and are not likely to be subject to any significant degree of multiphase interference effects.

Lastly, the c-61-E test well penetrated three potential reservoirs upon which SET conducted field-based DSTs to evaluate injectivity. Specifically, testing was performed on several porous sections within the Slave Point, Sulphur Point, and Keg River Formations. These in situ tests provided valuable data that were used to estimate the permeability and injectivity of the potential reservoirs. The key results of these DSTs are summarized in Table 1.

Table 1. Summary of DSTs Conducted on Three Potential Reservoirs

Potential Reservoir Formation	Net Effective Pay Thickness, m (porosity, %)	Permeability to Water, mD	Radius of Investigation, m	Qualitative Assessment of Reservoir Permeability
Slave Point	28.5 (6.6)	48	145	Moderate
Sulphur Point	22.1 (8.1)	572–797	66	Excellent
Keg River	12.3 (6.0)	24–42	186	Moderate

The following summarizes the characteristics of the Presqu'ile reef carbonate section of the site lithology and the related potential sinks that were found to occur at the c-61-E well location. The main reef starts below the Otter Park Formation where the c-61-E well encountered a 279-m-thick barrier reef consisting of:

- 103 m of Slave Point, primarily dolomite, which has a porous and permeable section that contained gas and water and into which the well began losing drilling fluid, which is indicative of moderate permeability (>40 mD).

- 5 m of Watt Mountain, tight, shaley dolomite, which will serve as a baffle, but not necessarily a seal, for upward migration of CO_2.

- 42 m of Sulphur Point, primarily dolomite, into which the well lost drilling fluids, indicating significant permeability (>500 mD). Because of large vugs, it was not possible to obtain a core sample of this formation.

- 129 m of Upper Keg River, primarily dolomite reef with some porosity.

The results of the exploratory drilling program, particularly the DST data and subsequent testing and analyses of cores and cuttings from the Sulphur Point and Upper Keg River Formations, provide substantial evidence that these formations have sufficient injectivity to serve as sinks for the Fort Nelson project.

CURRENT UNDERSTANDING OF HYDROGEOLOGICAL REGIME AND RESERVOIR COMMUNICATION

Hydrogeological Characterization

Hydrogeological Regime

Hydrogeology encompasses the interrelationships of geologic processes and materials (i.e., rock formations) with water (Fetter, 1994). It includes the study of water in deep geologic formations, with particular emphasis given to its chemistry, flow systems, and relation to the geologic environment (Sharp, 2007). The direction and rate of fluid flow in three dimensions within a rock formation or between groups of formations are collectively referred to as the hydrogeological regime of that geologic system. For a CCS project, a thorough and accurate understanding of the hydrogeological regime of the sink–seal system is essential for predicting both the movement and fate of the injected CO_2 and the dissipation of pressure from the reservoir. Hydrogeological data, including formation pressure and reservoir fluid chemistry data, must be collected and used to determine the existence and nature of hydraulic connectivity between different rock units. Hydrogeological data can also be used to support storage capacity estimates.

The hydrogeological regime in the Fort Nelson area is influenced by a variety of factors. At the regional scale, groundwater flow within the Devonian system is generally eastward, flowing away from the Rocky Mountains. However, at the local scale, flow within the Devonian system in the Fort Nelson area is complicated by the effects of reef structure and architecture, the distribution of porosity and permeability, and the impact of localized pressure drawdown as a result of major gas production from portions of the reef. With respect to flow rates, the available head data (Figure 16) suggest very slow, natural, in situ brine flow in the Fort Nelson area (Canadian Discovery, Ltd., 2009).

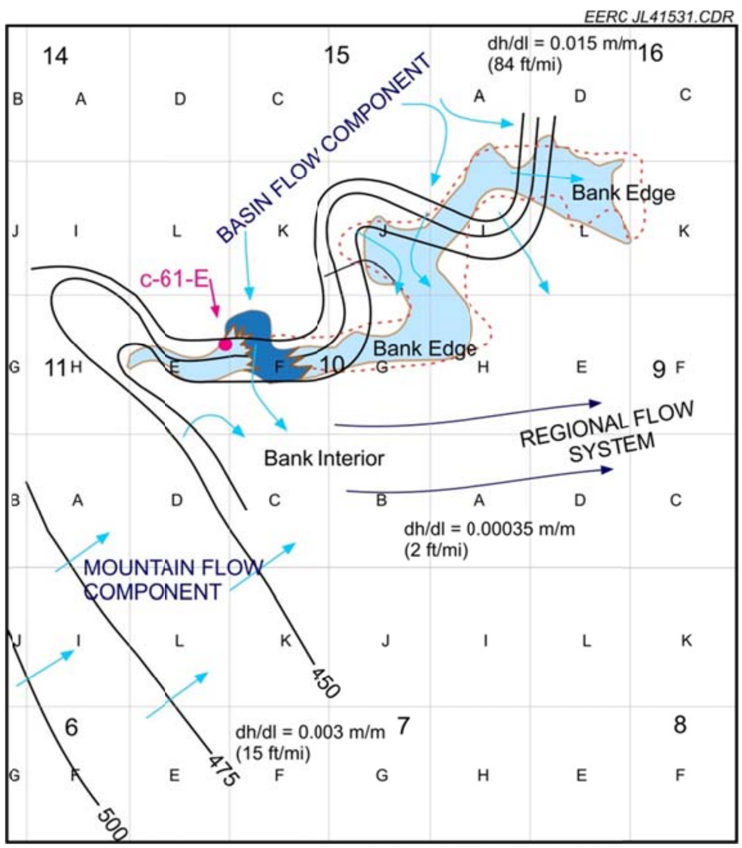

Figure 16. Local Fort Nelson site area head map (modified from Canadian Discovery, Ltd., 2009).

In 2008, SET commissioned a thorough study of the hydrogeological regime in the Fort Nelson area (Canadian Discovery, Ltd., 2009). The results of that study provide valuable insight into the nature of fluid flow into and within the Presqu'ile reef complex. The key findings of that study relative to the Fort Nelson project are discussed as follows in the context of characterizing the nature and extent of hydraulic and pressure communication between the various rock units of the sink–seal system. Understanding those relationships is critical to predicting the long-term movement and fate of the injected CO_2.

The Fort Nelson project was conducted based on a design that calls for injection and storage of sour CO_2 into either the Sulphur Point or Keg River Formations. The high permeability and large areal extent of these formations will accommodate the injected sour CO_2, specifically facilitating pressure dissipation and the movement of the in situ brine away from the point of injection. The other factor that controls the movement of injected sour CO_2 is bed dip and the related buoyancy factor. By injecting lower in the reef stratigraphy in the Sulphur Point or Keg River Formations, the sour CO_2 will tend to migrate structurally updip, as permitted by permeability and fractures. The following discussion looks at evidence for vertical and lateral communication within the reef for two important reasons:

- If the Slave Point and Sulphur Point are connected within the area, then the injected sour CO_2 will, at some point, migrate upward into the Slave Point. The overlying cap rock (Muskwa–Fort Simpson shales) will contain the buoyant movement of the injected fluid and force it to migrate updip, becoming trapped through imbibition along the way, where it will ultimately be trapped in structural highs.

- If all of the reservoirs in the reef complex are connected and form an extensive brine-saturated hydrogeological system in the deep subsurface, then pressure created from the large volume of injected sour CO_2 will be dissipated. An understanding of the nature of that pressure dissipation would be beneficial to the Fort Nelson project from both an operational and regulatory perspective, and the degree of connectivity must be established.

As there is remaining gas production from the Slave Point Formation along the edge of the reef complex, principally the Clarke Lake Slave Point A gas pool, it will be important to avoid contaminating the pools with injected fluids or adversely impacting offsetting operations with a pressure increase from the Fort Nelson project. Therefore, it is important to establish the extent of any connectivity along the reef to the gas pools which are currently under production.

Flow Within the Presqu'ile Reef and Communication Between Formations

As part of the Fort Nelson characterization activities, a head map was constructed for the Presqu'ile reef hydrogeological system to interpret the brine flow pattern. The head values include only head values from hydrogeological tests or wells with short gas columns and from data prior to major production at the Clarke Lake Slave Point A and Clarke Lake Slave Point B pools. Figure 16 shows the resulting head map for the Fort Nelson project study area prior to any major gas production. The contouring was done independently from knowledge of the bank edge, and as a result, the close grouping of contours at the northern edge of Figure 16 only partially follows the bank edge. The widely spaced contours on the western edge of the head map reflect flow from the recharge area in the mountains to the west.

Flow in the system, indicated by the blue arrows in Figure 16, is perpendicular to the contour lines and from higher head values to lower head values. The direction of flow is southward from the Keg River platform underlying the shale basin toward the Middle Devonian carbonate bank and from the southwest to the northeast along the bank interior. There is little data control in the bank interior, but the few head measurements suggest a slow, natural, in situ brine flow at the Fort Nelson site area. The head gradient varies from average to the southwest (5 m/mile) to moderate (26 m/mile) along the higher permeable bank edge. This natural brine flow will have some influence on the injected sour CO_2 in the postinjection phase of the project along with other factors such as buoyancy and the various trapping mechanisms.

In addition to understanding the natural brine flow in the Middle Devonian reef, there is another strong influence on flow within the reef system, and that is the pressure drawdown in the local Fort Nelson project area because of past and ongoing natural gas production. Just to the east of the proposed CO_2 injection area is the major Clarke Lake Slave Point A gas pool, which has been in production since 1961 and has produced just over 1.69 Tcf of raw sour natural gas and just less than 226 million barrels of formation water. The produced formation water is injected back into the Slave Point and Sulphur Point Formations underlying this gas cap.

Current understanding of the impacts of historic gas production on the pressure profile of the Presqu'ile reef complex in the Fort Nelson area is illustrated in Figures 17 and 18. Figure 17 shows initial pressure distribution in the reef before gas production and produced water disposal injection operations, while Figure 18 shows two interpretations (one based on actual pressure measurements and the other on post-history-matched simulations) of the current pressure distribution within the reef. These comparisons of the pressure profiles indicate that gas field production operations have resulted in a significant overall lowering of the pressure regime in the reef complex, which, in turn, further complicates the direction and magnitude of fluid flow in the Devonian system. There are two points to note:

- The produced saline water is disposed of into the Slave Point and Sulphur Point Formations with no measurable pressure buildup on the injection well, indicating that the pressures in the underlying hydrogeological system are representative of the regional pressure, which is less than hydrostatic and defines a regionally underpressured hydrogeological system.

- The removal of gas from the Slave Point A and B pools creates a cone of depression, or a low-pressure area, about the pools, particularly for the A pool, which widens and deepens with time. This low-pressure area will deflect the regional flow toward the producing pools.

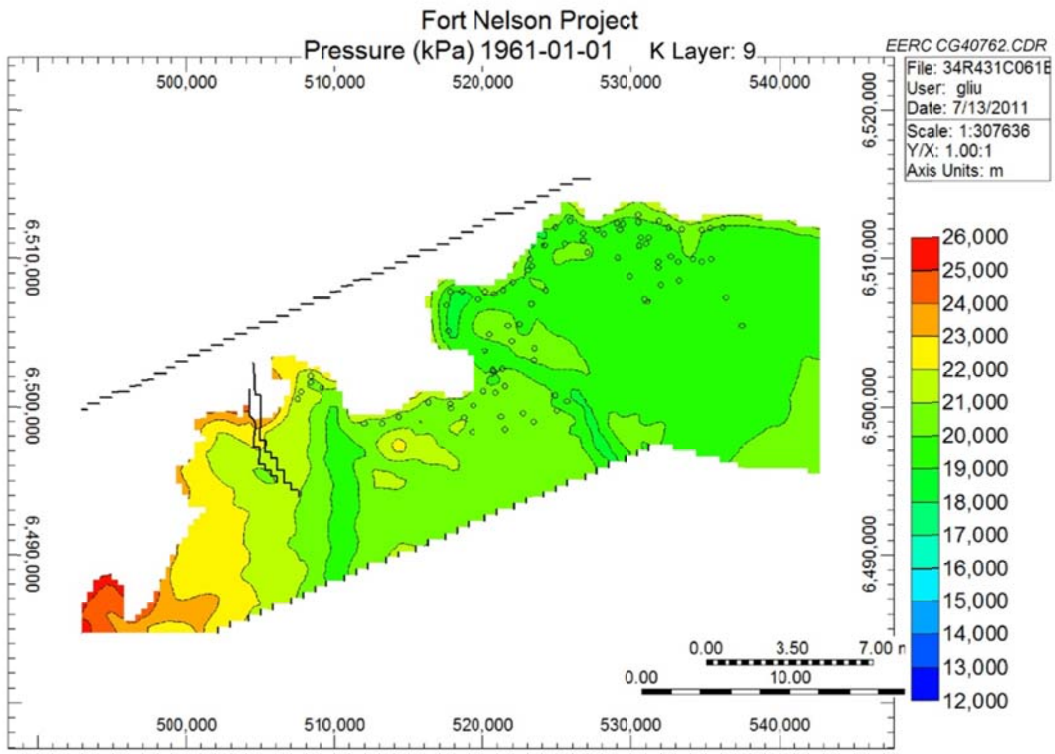

Figure 17. Pressure profile – initial pressure before production and injection operations (Sorensen and others, 2014b).

Figure 19 presents a pressure-versus-elevation plot for the wells along the reef edge. The graph shows the initial pressure in the preproduction to early production phases of the Clarke Lake Slave Point A pool and the subsequent pressure drop over time. On the graph, the 2009 and 2010 pressures from the SET Test Well c-61-E and Sidetrack d-61-E have been plotted. These pressures are affected by drawdown from producing Slave Point pools, which are more than 15 km away. The plot of the pressures from the SET test wells also shows the impact of Slave Point gas production on the deeper Sulphur Point and Keg River hydrogeological systems, which indicates communication exists between all three hydrogeological systems over a large area.

There is only minor production from the Clarke Lake Slave Point B pool, which also has a small water disposal operation in place; therefore, the main impact to flow in the Middle Devonian hydrogeological system in the Fort Nelson project study area is production from the Clarke Lake Slave Point A pool.

During injection at the Fort Nelson project site, the influence of the expanding cone of pressure drawdown from the Clarke Lake Slave Point A pool will tend to direct any sour CO_2 plume toward this gas pool. Consequently, it is vital to understand the brine flow pattern, taking into consideration the drawdown effects from Clarke Lake along with the key reservoir properties that impact plume migration (i.e., porosity and permeability trends, fractures,

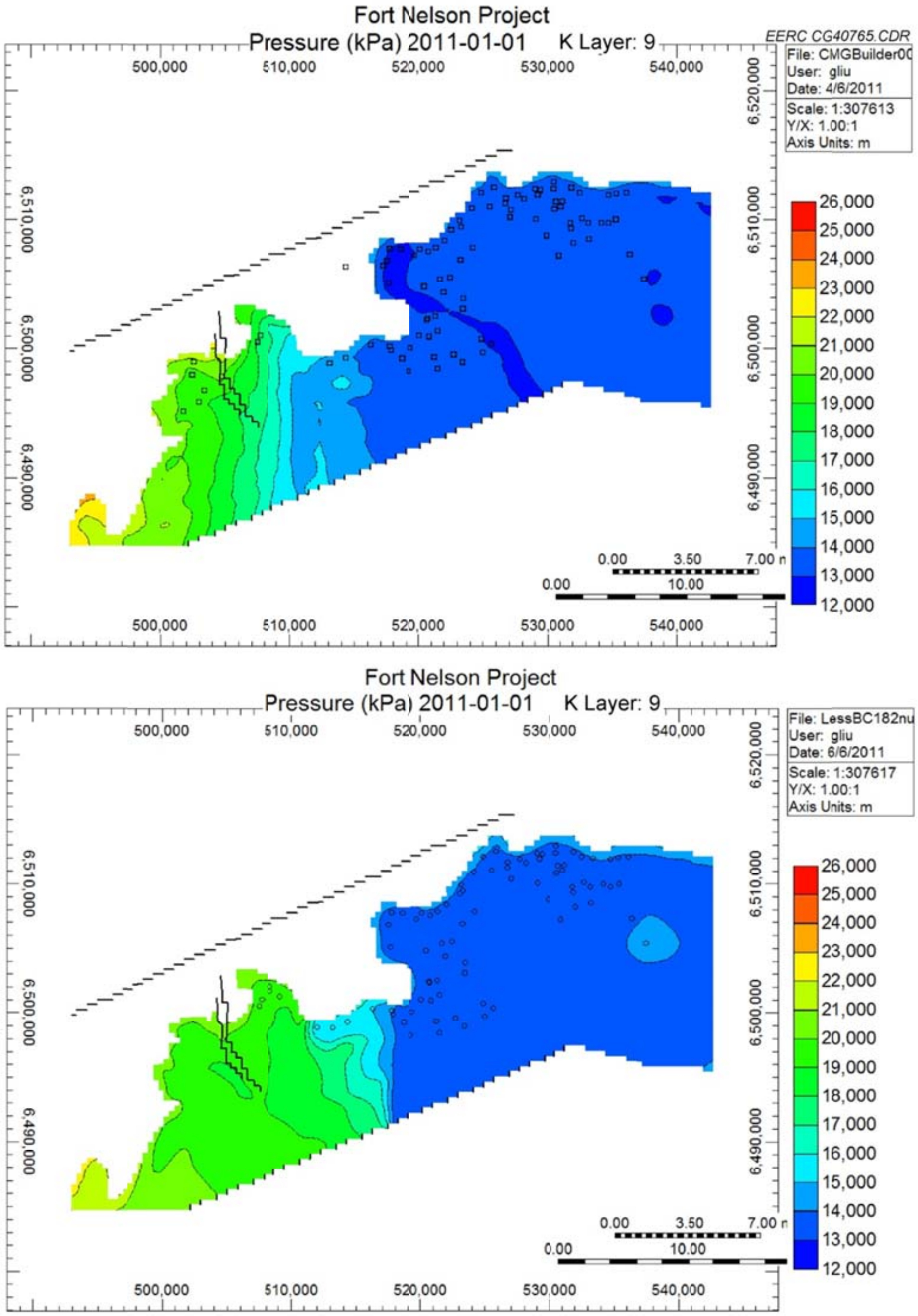

Figure 18. Pressure profile comparisons between measured distributions (top, after gas production but before sour CO_2 injection operations) and simulation results (bottom, after history matching before sour CO_2 injection operations) (Sorensen and others, 2014b).

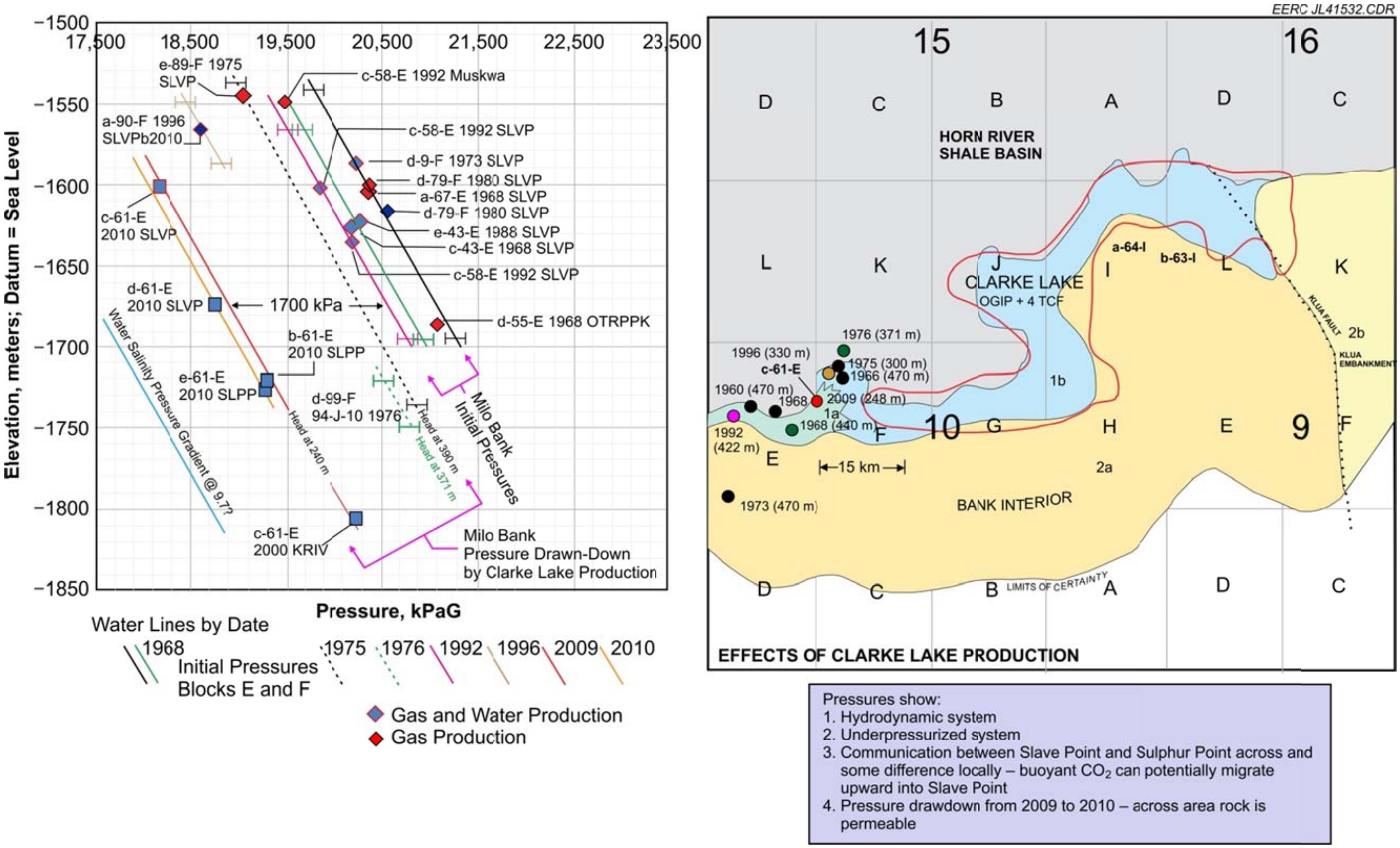

Figure 19. Fort Nelson project brine reservoir communication (modified from Canadian Discovery, Ltd., 2009).

structure, and the buoyant properties of sour CO_2). These factors impact the choice of the early injection sites for the Fort Nelson project that may have to be placed an appropriate distance from the currently producing pools, with closer sites drilled only when these producing Slave Point gas pools become uneconomical.

Indications of Vertical and Lateral Communications

Pressure, temperature, and fluid data were obtained as part of conducting DSTs in the c-61-E well and injection testing at the Sidetrack d-61-E. Figure 20 presents a pressure-versus-depth graph, with the pressure data points identified by formation and by year (i.e., c-61-E is 2009, and d-61-E is 2010). Review of the information on the pressure-versus-depth graph indicates the following:

- The Slave Point and Sulphur Point pressure data show that they are on the same pressure gradient, suggesting vertical communication.

- The 2009 Keg River pressure point is very close to the 2009 Slave Point–Sulphur Point water line, so it may be in the same system/aquifer. It is also possible that the Keg River pressure plots on a slightly different water line, suggesting that it could be in a separate aquifer. However, it is suspected that the Keg River is connected to the Sulphur Point based on knowledge of the geology in that area and that the slight difference in pressure can be accounted for as within the margin of error of the pressure gauges or by slight differences in the flow paths and, hence, the potential/pressure field. Based on this knowledge, it is possible that the Sulphur Point and Keg River may be parts of one extensive, dynamic, brine-saturated hydrogeological system.

- Pressure values from the 2010 data are slightly less than the 2009 pressures in both the Slave Point and Sulphur Point Formations by about 72 kPa. This pressure difference is significant, and it likely shows that the pressure decline is because of production from the Clarke Lake Slave Point A pool has reached at least as far as the location of c-61-E.

- The influence of the Clarke Lake Slave Point A pool on reservoir pressure has reached at least as far as the c-61-E location. This means that there is connectivity in the Slave Point and Sulphur Point reservoirs from the c-61-E location across the Fort Nelson project study area to this producing pool. In addition, it shows there is communication between Slave Point and Sulphur Point aquifers because the production at the Clarke Lake A pool is from the upper Slave Point. For pressure to be drawn down in the Sulphur Point as well, it means that the two formations are in communication in this area. At this time, reservoir information in the lower Slave Point to Keg River is sparse, and on the western part of the Fort Nelson study area, there is a lack of Sulphur Point and Keg River reservoir information as most wells were drilled only into the top part of the upper Slave Point.

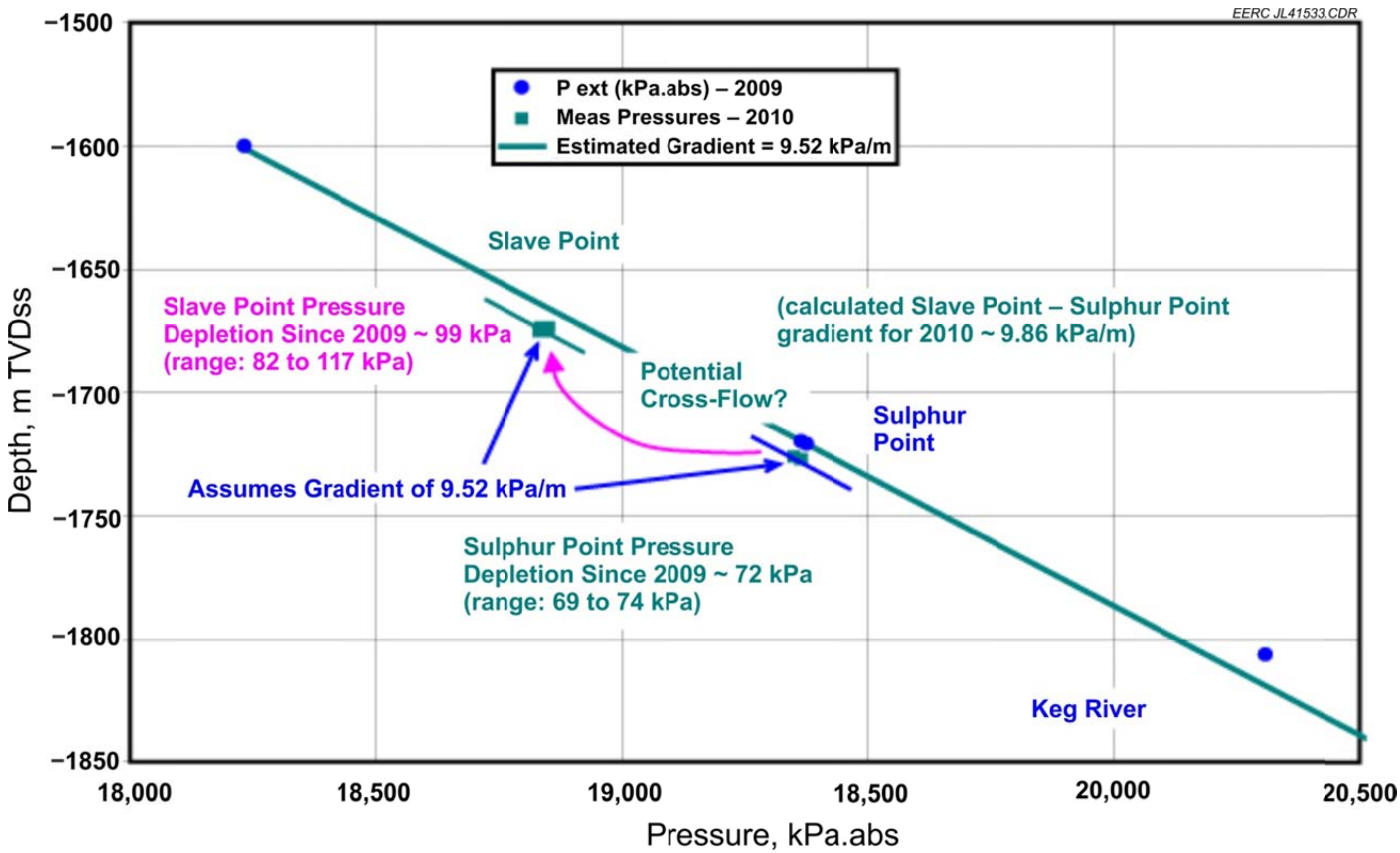

Figure 20. Pressure-versus-depth plot (c-61-E well and sidetrack well [d-61-E]) (modified from Canadian Discovery, Ltd., 2009).

- Review of pressure data, temperature data, and spontaneous potential well log information suggests brine flow took place between Slave Point and Sulphur Point. The brine flow, however, is not large. It is believed that in the general vicinity of the c-61-E wellbore, the Slave Point and Sulphur Point, although connected regionally, are separated locally by a tight Watt Mountain Formation (i.e., petrophysical analyses on d-61-E sidetrack shows it is 4.8 m thick and has no effective net porosity/permeability). This is understandable as the carbonate reef sequence is very heterogeneous in nature, causing permeability connections to vary locally; however, overall communication via various tortuous routes will occur. In the seismic interpretation and analyses to date, there are local features, such as sags and associated seismic character changes, that suggest a very thin or absent Watt Mountain in some areas of the Fort Nelson study area. It is postulated that hydrothermal pipes or sags, seen as circular features on the seismic surveys, penetrate through the Watt Mountain and other local aquitard layers. Also, the thin-to-absent Watt Mountain locations and small fractures may be potential avenues of vertical communication between the Slave Point and Sulphur Point reservoirs.

In summary, the evidence suggests that there is communication (laterally and vertically) across the Fort Nelson study area between the Slave Point, Sulphur Point, and Keg River Formations. Locally, there may be separation, depending on the areal extent and thickness of the Watt Mountain aquitard and the amount of fracturing and degree of dolomitization of the interval between the Slave Point and Sulphur Point reservoirs. The reef sequence between the Sulphur Point and Keg River has low permeability based on log porosities and limited core analyses. However, intense dolomitization and fracturing are suspected to be common and have been identified in the c-61-E logs, making it likely that communication occurs between these two reservoirs. This is supported by the pressure data from well tests.

Storage Capacity

Having a thorough understanding of the storage capacity of a given sink is necessary to determine the long-term viability of a CCS project. Simply stated, a target injection zone may have adequate injectivity to support high rates of CO_2 injection, but if there are physical constraints that limit the sustainability of those injection rates, then that zone will not be a viable sink. Subsurface characterization data provide the basis for estimating storage capacity. Using much of the data provided previously in this report, storage capacity estimates for the Slave Point, Sulphur Point, and Keg River Formations in the Fort Nelson project study area were developed in late 2010 (Sorensen and others, 2014b). These estimates were based on the available geologic characterization data and modeling conducted prior to December 31, 2010. A description of the approaches used to develop these storage capacity estimates and the results are presented as follows.

Void Replacement

A simple mass balance (i.e., void replacement) was performed by calculating the volume of fluids entering and leaving the Presqu'ile reef in the modeled area (2000 km^2), which includes the Clarke Lake Slave Point A and B gas pools (Sorensen and others, 2014b). Based on the volume of gas and water removed from the system, it was estimated that there is a CO_2 storage volume equivalent to approximately 137 million metric tons. This estimate was determined by summing the total volume of gas and water produced from the Clarke Lake Slave Point A and B gas pools and subtracting the volume of water injected back into the Presqu'ile reef in the modeled area. These volumes were converted to reservoir conditions using estimated formation volume factors for both the water and gas. The reservoir volume that was removed (i.e., the reservoir volume made available for CO_2 storage) from the Presqu'ile reef in the modeled area was then multiplied by the expected reservoir density of the injected sour CO_2 under the assumed reservoir conditions to yield 137 million metric tons of potential CO_2 storage (Table 2). Therefore, injecting 100 million metric tons of sour CO_2 into these formations over a 50-year period should not raise the regional formation pressure to the initial pressure, even if the system were closed, which it is not.

Table 2. Simple Mass Balance (i.e., void replacement) CO_2 Storage Capacity Estimate

	Standard Conditions, m^3	Reservoir Conditions,[1] m^3	CO_2 Mass,[2] metric tons
Gas Produced	50,344,931,159	326,000,000	135,000,000
Water			
Produced	39,456,222		
Injected	34,183,587		
Net Water Produced	5,272,635	5,000,000	2,000,000
Total Voidage Created by Production Operations		331,000,000	137,000,000

[1] Conversion to reservoir volumes was done using a formation volume factor of $B_g = 0.00648$ for natural gas and $B_w = 1.04$ for formation water.
[2] A CO_2 reservoir density of 415 kg/m^3 (average CO_2 density in the reservoir) was used to calculate the CO_2 storage mass.

Pore Volume Estimates

In addition to the void replacement calculations, the pore volume was calculated by estimating the pore volume in the formations from the reservoir model, without consideration of the produced fluids; i.e., pore space is the product of the area, thickness, and porosity of the formation (Sorensen and others, 2014b). Based on this approach, it is estimated that the pore space in the Slave Point, Sulphur Point, and Keg River Formations combined exceeds 29 billion m^3. Since it is known that the pore space is full of formation fluids, only a portion of this "pressure space" is available for CO_2 storage. From the literature (IEA Greenhouse Gas R&D Programme, 2009; U.S. Department of Energy National Energy Technology Laboratory Office of Fossil Energy, 2010), it is reasonable to estimate that 1% to 4% of the total pore space is available for an entire formation and an even higher percentage is available for a specific area within a formation. For the Fort Nelson project study area, a conservative estimate of available pore space (1% to 2%) was assumed in the pore volume estimate. On this basis, if the reservoir was not already depleted and injections were into a virgin reservoir, then 100 million metric tons of sour CO_2 would utilize less than 1% of the available pore volume in the study area. On the same basis, 2% of the pore volumes in the three permeable and porous formations in the study area is sufficient to store more than 240 million metric tons of sour CO_2 (Table 3) (Sorensen and others, 2014b).

Table 3. Estimated Effective Storage Volume of the 2000-km² Study Area Based on Pore Volume Estimates

Formations	Pore Volume, m^3	Storage Mass[1] (E = 1.00%), metric tons	Storage Mass[1] (E = 2.00%), metric tons
Slave Point	4,340,000,000	18,000,000	36,000,000
Sulphur Point	2,920,000,000	12,100,000	24,200,000
Keg River	22,200,000,000	92,100,000	184,200,000
Total	29,460,000,000	122,200,000	244,400,000

[1] A CO_2 density of 415 kg/m^3 was used to calculate the storage mass (average CO_2 density in the reservoir); E = percent of pore space available for storage of sour CO_2.

Modeled Storage Capacity

Storage capacity was also evaluated and estimated using numerical simulation techniques, the details of which are presented and discussed in Liu and others (2014). In summary, using a history-matched reservoir model, it was estimated that 100 million metric tons of CO_2 can be stored at the Fort Nelson project study area over a period of 50 years (i.e., 2 million metric tons per year) while only increasing the reservoir pressure/injection pressure about 2000 kPa above initial pressures. These results were in good agreement with voidage replacement and pore volume storage capacity estimates, further supporting the conclusion that the Presqu'ile reef in the Fort Nelson area has sufficient CO_2 storage capacity to serve as a commercial geologic storage site.

Summary of Geologic Characterization

The key findings from the geologic characterization activities conducted at the Fort Nelson project study area include the following:

- Compared to an oil or gas field, the amount of subsurface characterization data available for the Fort Nelson study area is sparse, and the level of uncertainty associated with interpretations of the Fort Nelson sink–seal system is relatively high. The acquisition of additional data is necessary to reduce this level of uncertainty to more acceptable levels.

- There are anywhere from 20 to 25 distinctly identifiable rock units present in the stratigraphic column of the Fort Nelson project study area. Multiple units in the Devonian-age Presqu'ile reef complex have the potential to serve as either sinks or seals for CO_2 storage.

- The Sulphur Point and Keg River Formations have been identified as being the most likely primary sinks for the Fort Nelson project.

- The results of the exploratory drilling program and subsequent analyses of cores and cuttings from Sulphur Point and Upper Keg River Formations indicate that those formations have sufficient injectivity to serve as sinks for the Fort Nelson project.

- While the Slave Point Formation likely has adequate porosity and permeability to serve as a sink, it is not considered to be a primary candidate formation for CO_2 storage because there are two commercially operated gas reservoirs in this formation that are in relatively close proximity to the injection sites being considered for the Fort Nelson project.

- The 550 m of shales of the Fort Simpson and Muskwa Formations have been identified as being the primary seals for CO_2 storage in the carbonate rocks of the Presqu'ile reef complex.

- The Devonian-age Watt Mountain Formation, which is primarily shale but whose occurrence is inconsistent in the Fort Nelson area, may serve as a baffle to upward migration of CO_2 from the underlying Sulphur Point Formation; however, it is not considered to be a seal.

- The Devonian hydrogeological evidence suggests that the Otter Park Formation is a tight, calcareous shale rock unit with occasional unconnected streaks of dolomitic porosity that directly underlies the Muskwa Formation. Although this formation is not technically considered to be part of the primary seal, it is believed that this generally low permeability formation will serve as a barrier to lateral and upward migration of injected sour CO_2.

- The results of a variety of petrographic, geochemical, and geomechanical laboratory testing on samples of the Fort Simpson and Muskwa shales from c-61-E provide strong evidence that these formations will serve as a competent vertical seal for the storage of sour CO_2.

- Seismic survey data and well log data from 96 wells indicate that structural complexity exists within the Presqu'ile reef complex in the Fort Nelson area. Structural elements that have been identified include a fault–graben system west of c-61-E and multiple hydrothermal sag features. These structural elements can exert considerable influence on the mobility and fate of injected CO_2 and the dissipation of pressure from the reservoir.

- There is communication, both laterally and vertically, across the Fort Nelson project study area in the Slave Point, Sulphur Point, and Keg River Formations.

- The Debolt Formation has been identified as a formation of interest to the Fort Nelson project because it is the first largely porous and permeable formation that occurs above the primary seal, i.e., the Fort Simpson shale, and it serves as a major source of water for hydraulic fracturing operations in the nearby Horn River shale gas play. It will, therefore, likely be targeted for monitoring for the first signs of CO_2 leakage outside the primary seal–sink system.

- Estimates of the sour CO_2 storage capacity of the Presqu'ile reef complex in the Fort Nelson project area range from 100 million to over 240 million metric tons. These results are supported by multiple estimation methodologies including void replacement calculations, pore volume estimates, and numerical predictive simulations. The latter was based on a history-matched model, which assumed the injection of 2 million metric tons per year of CO_2 over a 50-year period, using three injection wells, and predicted increases in reservoir pressure well within the maximum acceptable limits for the storage system.

GEOCHEMISTRY

For multiple reasons, it is important to understand the potential geochemical reactions that may occur during CO_2 storage projects in deep saline formations. This is particularly important in carbonate rock formations because, under some conditions, carbonate minerals (e.g., calcite and dolomite) can be reactive with the carbonic acid that is created by the dissolution of CO_2 into formation water. These reactions can result in dissolution and/or precipitation of minerals in different parts of the reservoir, depending on conditions. To evaluate the efficacy of CO_2 storage, it is important to assess the likely chemical changes in the reservoir fluids, CO_2 mineralization pathways and reaction kinetics, near- and long-term stability of the minerals formed during injection, and long-term fate of unmineralized CO_2 in the reservoir. Dissolution of minerals can enlarge existing pores and open pore throats, thereby increasing the porosity and permeability of a formation. Conversely, precipitation of minerals can clog the pores and cause a reduction of porosity and permeability. From a reservoir engineering perspective, it is, therefore, important to determine how potential mineral dissolution and/or precipitation may or may not affect the near- and far-wellbore environments and the long-term injectivity and mobility of CO_2 and water.

Geochemical data also play a critical role in monitoring for the effects of CO_2 storage in zones above the sink–seal system. Understanding the geochemical reactions and reaction kinetics that may occur in the shallow subsurface (groundwater zone) or at the surface in the event of out-of-zone migration aids in determining chemical leak indicators in overlying surface and groundwaters, thereby increasing the likelihood of early detection through monitoring efforts. Verifying the geochemical integrity of the reservoir seal is important from a CO_2 injection, storage, and monitoring perspective because, ultimately, the seals are what keep the injected CO_2 from migrating out of the target injection zone. Determining the geochemistry of a CCS system can be accomplished by conducting field-, laboratory-, and modeling-based studies. As with the geological characterization activities, the Fort Nelson project conducted a number of geochemistry-oriented efforts, the approaches and results of which may provide guidance for future CCS projects in deep carbonate saline formations.

GEOCHEMICAL CHARACTERIZATION AT FORT NELSON

A series of geochemical laboratory tests were conducted from 2009 through 2011 to develop basic information on 1) the mineral and petrophysical characteristics of key cap rock, transition-zone rock, and reservoir rock of the Fort Nelson project and 2) the geochemical reactions of these rocks with CO_2 and sour CO_2 at reservoir conditions. The primary goals of these activities were as follows:

- Identify the predominant mineral phases of the potential sink and seal formations.
- Determine the reactivity of the cap rock, transition zone, and reservoir rock with CO_2 and sour CO_2 at reservoir conditions.
- Determine the mineral dissolution and precipitation potential resulting from the exposure of the cap rock, transition zone, and reservoir rock to CO_2 and sour CO_2.
- Determine potential changes in reservoir fluid properties as a result of sour CO_2 injection.

These geochemical data will provide valuable insights regarding the impact of sour CO_2 exposure on the planned CCS operations at the Fort Nelson site, with an emphasis on addressing the following critical operational questions:

- How will CO_2 injectivity be affected?
- How will CO_2 storage capacity be affected?
- What is the potential impact of these geochemical processes on the competency of the storage and sealing formations?

The scope of geochemical laboratory work conducted included sample collection and the conduct of five sets of batch reactor tests. These tests provided insights into the answers to these questions and included mineralogical/petrophysical characterization of "as-received" drill cutting samples and batch reactor tests at reservoir conditions to investigate the nature of the potential reactions of these samples with CO_2 and sour CO_2. The remainder of this section describes a summary of the sample collection effort; provides an overview of the experimental design; describes the five sets of batch reactor tests and analyses that were performed; and summarizes the major conclusions that resulted from the baseline mineralogical, petrophysical, and geochemical characterization of the drill cuttings and the comparisons of these preexposure (baseline) results to postexposure results. A detailed description of the geochemical laboratory test program for the Fort Nelson project and the experimental results can be found in the PCOR Partnership preliminary geochemical observations report (Sorensen and others, 2014c).

Sample Collection and Laboratory Test Program

During the drilling of Exploratory Well c-61-E in April 2009, samples of well cuttings were collected from the 1840–2240-m-depth interval, which makes them representative of the cap rock, transition zone rock, and reservoir rock of the following geologic formations: Fort Simpson, Muskwa, Slave Point (Upper and Lower), Watt Mountain, Sulphur Point, and Keg River. Overall, 160 vials of well cuttings were collected, each containing approximately 7–9 g of material (Figure 21). In addition to the well cuttings, nine core samples representing the Fort Simpson, Upper and Lower Slave Point, Sulphur Point, and Keg River Formations, were also available for use in the geochemistry evaluation. Of the 160 vials of drill cuttings, a total of 26 samples were collected for laboratory testing. These samples were taken across depth intervals ranging from approximately 5 to 15 m in length and included the following:

- Cap rock formation
  - Fort Simpson shale (11 samples)

- Transition rock formations
  - Otter Park shale (five samples)
  - Upper and Lower Slave Point dolomite (five samples)

- Reservoir rock formations
  - Sulphur Point dolomite (two samples)
  - Upper Keg River dolomite (three samples)

Figure 21. Example of "as-received" well cuttings from Exploratory Well c-61-E/94-J-10.

The laboratory evaluations of the seal, transition, and reservoir rock well cuttings included the following:

- Mineralogical/petrophysical characterization of the "as-received" rock samples.

- Batch reactor experiments to investigate the potential reactions of the rocks with sour CO_2, with an emphasis on understanding the nature and kinetics of the reactions.

A summary of these laboratory evaluations follows.

Mineralogical/Petrophysical Characterization of Rock Samples

A suite of analytical tools and techniques was used to determine the mineralogical, chemical, and petrophysical characteristics of the cutting samples, both as-received cuttings as well as after exposure to sour CO_2 under varying CO_2 and H_2S concentrations, temperatures, and pressures. The goal of this testing was to apply an array of analytical tests that would allow for the mineralogical characterization of the cap rock, transition-zone rock, and reservoir rock and the detection of mineralogical changes in these rocks that might occur following exposure to sour CO_2 at reservoir conditions.

The specific analytical tools and techniques that were applied to all, or a portion, of the cutting samples as part of this geochemistry program included XRD, XRF, and SEM–EDS. When used together, these devices provide a highly developed characterization of sample mineralogy that includes bulk percentages of crystalline phases as well as trace minerals and chemical composition. Indirect information regarding the sample mineralogy was also generated by analyzing the brines that were in contact with the drill cuttings during their exposure to the sour CO_2 using ICP–MS.

Batch Reactor Test Program

The batch reactor experiments were conducted as five separate studies designated as Batch Reactor Test 1 (November 2009), Batch Reactor Test 2 (November 2010), Batch Reactor Test 3 December 2010), Batch Reactor Test 4 (January 2011), and Batch Reactor Test 5 (February 2011). A detailed description of the methods and results of those experiments are presented in Sorensen and others (2014c).

The Batch Reactor Test 1 experiments were focused on finalizing the experimental design and were based on several assumptions about average pressure and temperature conditions as well as brine and gas composition. For example, the brines used in these tests consisted of a simple solution of 2.5% NaCl in water.

The test conditions of the subsequent batch reactor experiments, Batch Reactor Tests 2–5, were modified based on preliminary reservoir modeling of the Fort Nelson project site that was performed in-house at the EERC and site-specific data that were provided by SET, e.g., a synthetic brine was prepared based on analytical results from field samples of the formation brine. Batch Reactor Tests 2 and 4 were conducted under near-wellbore conditions (3500 psi and

65°C), and Batch Reactor Tests 3 and 5 were conducted under far-from-wellbore conditions (2800 psi and 120°C). Table 4 provides a summary of the test conditions for Batch Reactor Test 1, and Table 5 provides a summary for the test conditions for Batch Reactor Tests 2–5. A more detailed discussion of each of these studies is presented in Sorensen and others (2014c).

Table 4. Test Conditions for Batch Reactor Test 1[1]

	Batch Reactor Test 1 (November 2009)	
Test Material:	Cap Rock, Transition-Zone Rock, and Reservoir Rock (1960–2200 m) (drill cuttings and powdered rocks)	
	CO_2 Reactor	CO_2–H_2S Reactor
Pressure	20.7 MPa (3000 psi)	20.7 MPa (3000 psi)
CO_2 Partial Pressure, mol%	100	95
H_2S Partial Pressure, mol%	0	5
Temperature	100°C (212°F)	100°C (212°F)
Saturation Conditions	Synthetic brine[2]	Synthetic brine

[1] All tests were conducted for a duration of 28 days using a sample mass of 2–3 g.
[2] Synthetic brine consisting of 2.5 wt% NaCl.

Table 5. Test Conditions for Batch Reactor Tests 2–5[1]

	Batch Reactor Test 2 (November 2010)		Batch Reactor Test 4 (January 2011)	
Test Material:	Cap Rock, Transition-Zone Rock, and Reservoir Rock (2005–2240 m) (drill cuttings only)		Cap Rock (1845–2000 m) (drill cuttings only)	
	CO_2 Reactor	CO_2/H_2S Reactor	CO_2 Reactor	CO_2/H_2S Reactor
Pressure	24.1 MPa (3500 psi)	24.1 MPa (3500 psi)	24.1 MPa (3500 psi)	24.1 MPa (3500 psi)
CO_2 Partial Pressure, mol%	100	86.5	100	86.5
H_2S Partial Pressure, mol%	0	13.5	0	13.5
Temperature	65°C (149°F)	65°C (149°F)	65°C (149°F)	65°C (149°F)
Saturation Conditions	Synthesized brine[b] Synthetic brine[c]	Synthesized brine Synthetic brine	Synthesized brine Synthetic brine	Synthesized brine Synthetic brine
	Batch Reactor Test 3 (December 2010)		Batch Reactor Test 5 (February 2011)	
Test Material:	Cap Rock, Transition-Zone Rock, and Reservoir Rock (2005–2240 m) (drill cuttings only)		Cap Rock (1845–2000 m) (drill cuttings only)	
	CO_2 Reactor	CO_2/H_2S Reactor	CO_2 Reactor	CO_2/H_2S Reactor
Pressure	19.3 MPa (2800 psi)	19.3 MPa (2800 psi)	19.3 MPa (2800 psi)	19.3 MPa (2800 psi)
CO_2 Partial Pressure, mol%	100	86.5	100	86.5
H_2S Partial Pressure, mol%	0	13.5	0	13.5
Temperature	120°C (248°F)	120°C (248°F)	120°C (248°F)	120°C (248°F)
Saturation Conditions	Synthesized brine Synthetic brine	Synthesized brine Synthetic brine	Synthesized brine Synthetic brine	Synthesized brine Synthetic brine

[1] All test were conducted for a duration of 28 days using a sample mass of 2–3 grams.
[2] Synthesized brine – brine prepared to mimic site-specific composition of formation waters, based on SET brine analysis.
[3] Synthetic brine – 2.5 wt% NaCl.

Summary of Geochemical/Petrophysical Characterization Results

The Fort Nelson project geochemistry laboratory test program investigated the effects of four factors that have the potential to cause mineralogical reactions at different locations within the reservoir: 1) pressure, 2) temperature, 3) brine composition, and 4) sour CO_2 composition. General observations and conclusions drawn from these test program results regarding 1) the mineral and petrophysical characteristics of key cap rock, transition-zone rock, and reservoir rock of the Fort Nelson project site and 2) the expected (or theorized) geochemical reactions of these rocks with CO_2 and sour CO_2 at reservoir conditions are provided in the remainder of this section. The possible geochemical reactions between the formation rocks and the CO_2 or sour CO_2 include carbonate mineral dissolution, calcite precipitation, iron mobilization and precipitation, elemental sulfur deposition, and ion exchange in clays and carbonates.

The determination of CO_2 and sour CO_2 exposure effects on the formation rocks at reservoir conditions is limited by the size of the data sets that were generated during this screening study. Because of the natural mineralogical variability within each formation, numerous samples are required before statistical conclusions can be drawn, i.e., analytical method uncertainty and natural variability of formation mineralogy and chemical composition need to be statistically quantified. However, even with these limitations, it was still possible to identify several data trends and general observations from this screening study:

- No significant changes in mineralogy were observed in the cap rock, transition-zone rock, or reservoir rock during exposure to either pure CO_2 or sour CO_2 at any of the reservoir conditions that were investigated. However, minor shifts in chemical composition were observed that suggest dolomite dissolution and calcite, halite, and sulfur precipitation may occur at both near-wellbore and far-from-wellbore conditions.

- Exposure of formation rock to pure CO_2, as compared to sour CO_2, may result in a higher probability of cementing material dissolution, including calcite, gypsum, and pyrite, as well as the mobilization of iron from the clay and carbonate mineral matrix. This suggests that the likely sour CO_2 composition may be less reactive at the Fort Nelson site.

- These limited data suggest that dissolution of carbonates from cement, within both the cap rock and reservoir rock, may occur during exposure to CO_2 or sour CO_2. Confirmation of this dissolution and an assessment of its potential effect on the mechanical strength of the rock would require further geomechanical laboratory testing using a larger sample set combined with numerical modeling.

- Based on the samples available for this study, the potential for calcite and calcium chloride precipitation appears to be minimal and on the order of less than 1 wt%; however, the significance of these precipitation reactions on reservoir injectivity for other formations requires further investigation. The deposition of minor amounts of sulfur and sodium chloride was also observed, although the effects of these reactions are likely to be less significant because of the instability of these compounds under reservoir conditions.

- The potential for iron deposition was also observed in a limited set of samples. This deposition could affect injectivity into the reservoir as a result of the precipitation of iron hydroxide. Iron displacement by hydrogen also has the potential to reduce the mechanical strength of the cap rock and the reservoir rocks. However, because of the sampling technique employed in this study, it is likely that the observed iron was present in the cuttings because of contamination by drilling debris and was not representative of the reservoir or sealing formations. Further investigation of this hypothesis is warranted.

- The chemistry of the reservoir fluid is important. Analysis of the synthesized brine showed little to no effect during rock exposures to high-pressure CO_2, whereas the NaCl synthetic brine showed increased calcium and magnesium concentrations under the same conditions.

Overall, the results of this screening geochemical study suggest that the development of an adequate understanding of the occurrence and subsequent effects of potential dissolution and precipitation reactions will require further investigation through a series of targeted, more detailed geochemical and geomechanical investigations. Some investigations of particular interest include the following:

- Laboratory studies to verify the preliminary observations regarding the geochemical reactions of iron-bearing minerals in the formation rocks and iron mobilization reactions. The production of such minerals as hematite, pyrite, and other iron-bearing minerals would be investigated during these tests.

- Analysis of sealing unit core plug samples as-is and following exposure to supercritical CO_2–H_2S in batch reactor tests at reservoir conditions using various petrophysical techniques, such as XRD and SEM.

PREDICTING THE MOVEMENT AND FATE OF INJECTED CO_2

The geological storage of CO_2 is a complex process that depends on the full breadth of geologic conditions within the sink–seal system. As described above, a wide variety of data that describe the petrophysical, geomechanical, hydrodynamic, geochemical, and geothermal conditions of the sinks and seals, at scales ranging from near-wellbore to regional, are necessary to determine the suitability of a potential CCS project location. Static and dynamic numerical modeling is a means of using these data to understand, evaluate, and predict the fate and potential impacts of the injected CO_2 and associated pressure increases. As such, modeling is an essential component of the knowledge base upon which decision-making stakeholders (e.g., government regulators, commercial operators, etc.) will evaluate the viability of a CCS project. However, it is important to note that the reliability and inherent usefulness of the modeling is heavily influenced by the quantity and quality of the data upon which it is based. The more limited the data set, the greater the uncertainty in predicted outcomes from the model. The level of uncertainty in model predictions can be reduced by history matching of 1) past fluid production and/or injection activities in the vicinity of a proposed location, 2) laboratory experiments conducted on representative samples under anticipated reservoir conditions, and/or 3) observations of reservoir response from pilot-scale injection testing in the field.

During the feasibility study stage of a CCS project that targets a deep saline formation, the geological characterization data are likely to be of relatively limited quantity and variable quality. Because of that, robust modeling of multiple potential injection scenarios in a wide variety of geostatistically based geological settings that are relevant in the context of the sink–seal being considered is crucial to project success. Such modeling will provide stakeholders with a sufficient technical basis for identifying, assessing and, ultimately, managing the risks that will be associated with the CCS project. This, in turn, will provide a foundation for design and implementation of an effective, comprehensive MVA plan for the CCS project in question. Once a CCS project is approved and developed and begins commercial operation, then the models can be further refined with new operational and monitoring data to provide greater accuracy and confidence in predicting the fate and effects of the injected CO_2. It was with these concepts in mind that a robust program of numerical modeling was conducted as part of the Fort Nelson project. This program included static petrophysical reservoir modeling, dynamic injection and plume migration simulation modeling, and history matching using historical fluid injection and production data from gas production and produced water disposal wells in the Fort Nelson area.

The regional petrophysical reservoir model for the Fort Nelson area covers a volume defined by 39 km × 67 km × 800 m, containing the injection formation and adjacent gas pools (Clarke Lake Slave Points A and B) (Liu and others, 2014). These activities include static geologic model development as well as dynamic modeling and simulations that were conducted for the model validation, predictive simulation, and RA. The current static geologic model (Version 3) has been updated from two previous versions (Version 1 and Version 2) after incorporating new geologic information and more detailed data analysis. A detailed presentation of the methods, results, and interpretations of the Fort Nelson modeling activities are provided in Liu and others (2014). An overview summary of the key aspects of those modeling activities and highlights of the critical results pertaining to RA and MVA planning are described below. All results presented in this report are based on Version 3 of the static geologic model.

MODELING APPROACH FOR FORT NELSON

The method used in this study is an integrated, iterative, risk-based approach for defining MVA strategies (Figure 7). Site characterization, modeling and simulation, RA, and the development of a cost-effective MVA plan are the four key components iterated during the course of a CCS project. This approach will be applied through the feasibility, design, injection, closure, and postclosure periods of the project. Each iteration will improve the technical and cost-effectiveness of the MVA plan while simultaneously reducing project risks.

Static and dynamic modeling play a crucial role during each iteration of the risk-based MVA strategy used for the Fort Nelson CCS Project.

In order to more effectively integrate the modeling and simulation into the overall MVA strategy, a dynamic modeling workflow was developed (Figure 22) (Gorecki and others, 2012).

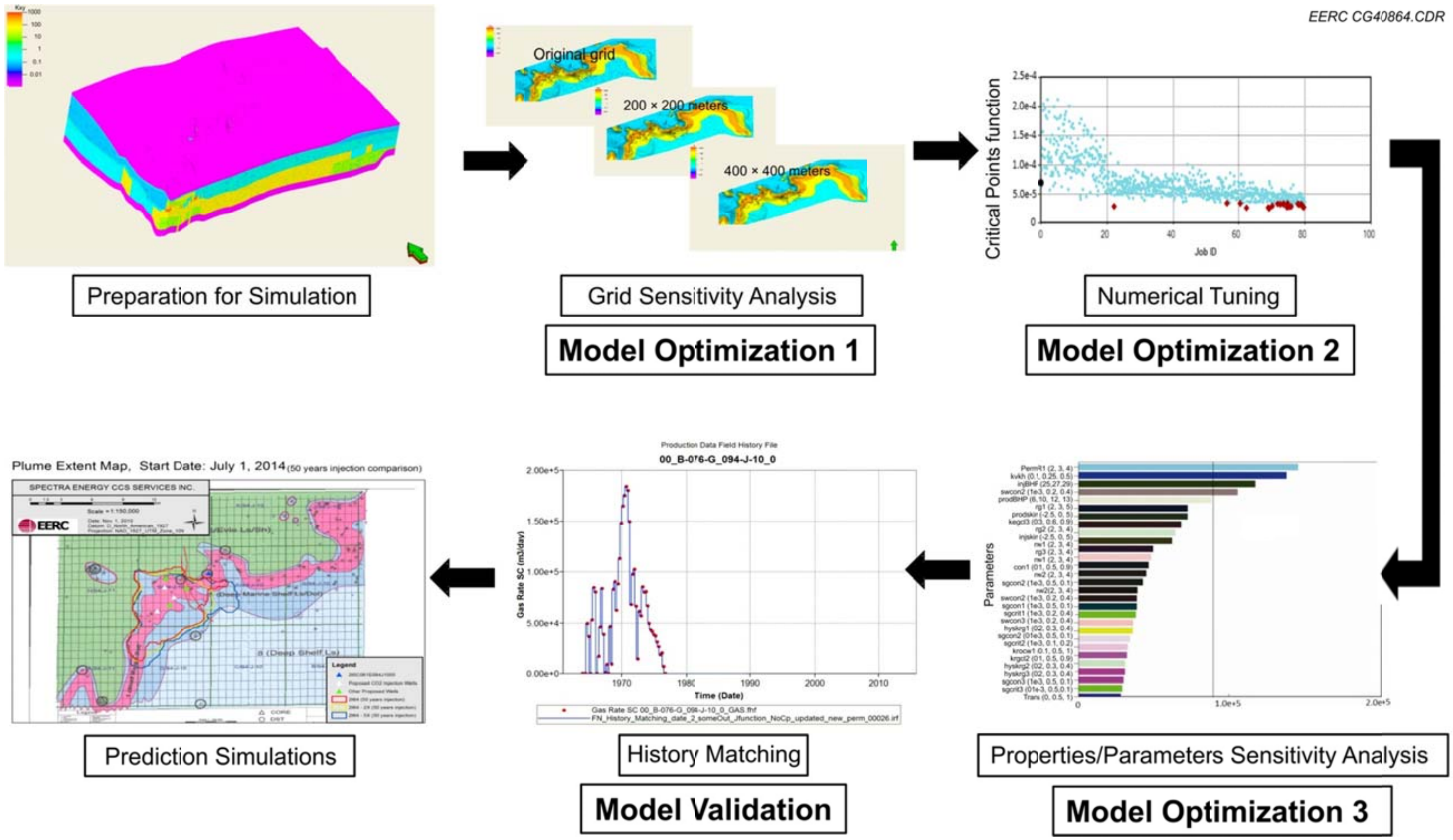

Figure 22. Dynamic modeling workflow used for the Fort Nelson project.

The workflow utilizes three techniques: 1) grid-size sensitivity analysis to create the coarsest grid resolution that will yield accurate results; 2) numerical tuning to speed up simulation run time and minimize materials balance error; and 3) properties/parameters sensitivity analysis to identify the properties and parameters that have the greatest effect on the simulation results. The optimized model was then validated by history matching to obtain a reasonable match between simulated results and historical data before any predictive CO_2 simulations are run (Gorecki and others, 2012).

After the model optimization and validation were completed, predictive simulations were run to determine fluid migration and pressure propagation. This information was then used as a basis for a subsurface technical RA. Through the course of running the predictive simulations and RA, areas of additional characterization and potential risk were identified, leading to several additional iterations of the risk-based MVA approach.

STATIC GEOLOGIC MODELING DEVELOPMENT

The Version 3 static reservoir model has evolved from a scoping-level model to a more detailed model that was completed in June 2010. The Version 3 model updated the previous two versions with the addition of detailed data such as 2-D and 3-D seismic data and core and well log analyses; refined 13 domains and ten zones; and included surface elevations from the topographic map and a temperature gradient to closely resemble a real sink–seal system for CO_2 storage evaluation and RA after model validation (history matching). An overview of each model version is provided in Liu and others, (2014). Static reservoir modeling based on the geological characterizations included Versions 1–3, evolving from a scoping-level model to a more detailed model.

Version 3 Model

The Version 3 model was developed by the EERC with input from the SET geological characterization team. Based on available geophysical and seismic data, 13 domains and ten zones were identified. Domains were based on zones of consistent rock properties that may relate to a depositional setting or structural feature. In some cases, a domain may cross formation boundaries (e.g., Upper Chinchaga and Lower Keg River). The formation intervals that were included in the 13 domains are the Fort Simpson, Muskwa, Otter Park, Upper and Lower Slave Point, Watt Mountain, Sulphur Point, Upper and Lower Keg River, and Upper and Lower Chinchaga Formations (Figure 15).

From available petrophysical and seismic data, the potential injection unit was modeled as primarily dolostone rock (~95%), representing depositional environments of middle and upper foreslope to reef margin shoal. The lithofacies were determined as grainstones, rudstones, and floatstones. Dominant biota is represented mainly by dendroid to tabular stromatoporoids and thamnopora corals. The matrix includes secondary dolomitization, vugs, and fractures. Average porosity, determined from core analysis, was estimated as 9%, and permeability, based on DST analysis, was estimated in the range of 50–200 mD.

Based on the available geophysical data, several iterative static models were constructed. After a meeting in June of 2010 and after the additional information became available, a revised static geologic model was constructed. Porosity and permeability by domain and zone were populated with a data set provided by SET. Surface elevation from the topographic map was added, and the temperature gradient was updated with the data from Canadian Discovery Ltd. (2009). Seismic data were used as an aid in assessing the variogram ranges. Refined interpretation of structure contour and small synthetic and antithetic faults from seismic data were populated (Figures 13 and 14).

The main updates in the Version 3 model are summarized as follows:

- More detailed log analyses and the newly reprocessed 2-D and 3-D seismic data.

- An updated structural model developed by the SET geological characterization team to include a better definition of the reef edge, formation boundaries, and features that create a structural trap.

- Heterogeneous reservoir properties, such as permeability and porosity, based on a more detailed understanding of their distribution throughout the model, not only vertically (from well logs), but also laterally (from the seismic data).

Three to six injection wells were utilized in the Version 3 model simulations. Most were focused on an area located more than 5 km west from the original Well c-61-E, although there were a few cases run around the original c-61-E for a more accurate comparison. Injection and CO_2 plume migration simulations were conducted under a variety of different injection locations and operational scenarios (Liu and others, 2014).

FORT NELSON DYNAMIC MODELING AND SIMULATIONS

The dynamic model was built using static geologic model Version 3. The initial simulations include a base case and initial scenario explorations for investigating the impact of reservoir properties/parameters such as permeability, the ratio of vertical permeability to horizontal permeability (k_v/k_h), and fault transmissibility on CO_2 plume and pressure buildup. The model was then optimized by introducing three techniques: grid-size sensitivity analysis, numerical tuning, and property/parameter sensitivity analysis, to reduce simulation run time. The optimized model was validated by history matching to obtain a reasonable match between simulated results and historical data. The top two “best”-matched numerical models were selected for predictive simulations for both injection locations: c-47-E and c-61-E.

Model Optimization and Validation

The dynamic model was optimized and validated by using a dynamic modeling workflow process developed and applied by the EERC. This workflow process includes three optimization techniques (grid-size sensitivity analysis, numerical tuning, and properties/parameters sensitivity analysis), model validation (history matching), and predictive simulations (Liu and others, 2014).

The model validation process was used to improve modeled outputs for obtaining a good match with historical data, which demonstrates the ability of the model to accurately predict reservoir conditions. As a commonly used technique, history matching is a method of adjusting, or tuning, reservoir characteristics (properties) to match historical field data through an iterative trial-and-error process. This trial-and-error process varies parameters and properties within accepted and realistic engineering and geologic ranges while still reasonably matching the simulated results with the historical data.

History-Matching Validation Data

Gas and water production and water disposal data within the Fort Nelson project study area were used for the history matching. Monthly (being averaged as a quarterly data set for history matching) gas and water production data, injected water volumes, and scatter points of bottomhole pressure (BHP) for 85 production wells and seven water disposal wells were used for the history-matching activities. These data for all of the production wells covered the time period from 1961 to 2010.

History matching was primarily based on achieving a satisfactory mass balance on the cumulative gas and water production data and water disposal data within the time period of 1961 to 2010. Once primary matching of the mass balances yielded a satisfactory global objective function tolerance, simulated and historical data values for gas and water production and BHPs for all of the individual wells were evaluated.

A global objective function was used in history-matching processes to measure the relative difference between the historical data and simulation results. Well variables were taken into account in the function via a root mean squared error (RMSE) method. With respect to history matching, smaller error values indicate a smaller difference between historical data and simulated values. As this error value decreases, the matching procedure tends to converge. After multiple iterations, the global objective function can be used to obtain an overall minimum error value (Yang and others, 2007). In this study, the global objective function was used for history matching of gas and water production, water disposal, and BHP.

History Matching

A history-matching process was used to improve modeled outputs and to obtain a good match with historical data, which demonstrates the ability of the model to accurately predict reservoir conditions. A total of 92 wells were utilized, including 85 production wells and seven water disposal wells in the study area, primarily in Gas Pools A and B. The goal of this step was to match gas and water production, water disposal, and well BHP. Ultimately, by matching these parameters in the nearby gas pools, a more accurate geologic model with a current matched distributed regional pressure profile could be used. After 494 history-matching simulation runs, an asymptotic convergence was achieved with a total of 92 wells matched (Figure 23A). Upon convergence, the global objective function error between the simulation runs and the historical data is 3.91% (Figure 23B). Correspondingly, Figures 23C and 23D show a comparison of the historical and simulation data for cumulative gas production and cumulative water disposal.

These history-matching results indicate a good match for gas and water production, water disposal, and BHPs for all wells in the investigated area (Gorecki and others, 2013).

The fieldwide distributions of the initial pressure (before history matching) and the measured pressure (January 2011) are shown in Figures 24A and 24B, respectively. The simulated pressure distributions obtained after history matching were replicated by introducing boundary settings and a lower-permeability barrier between Gas Pools A and B to mimic the observed trends in the historical data (Gorecki and others, 2013). The overall field pressure matches throughout the transient region between gas pools and the injection region with a few small deviations (Figure 24C).

Predictive Simulations Around Test Well c-61-E

Once the geologic model was matched to the historic production and injection in the nearby gas fields, predictive simulations were run to investigate CO_2 and pressure movement in and around Test Well c-61-E. Sour CO_2 was injected in Test Well c-61-E and two other locations (Track 1) in the immediate vicinity at a combined rate of 3.4 MMm^3/day (120 MMscf/day) for 25 years (Figure 25). The simulations were run for a total of 100 years, with 75 years of postinjection to address CO_2 movement and reservoir pressure buildup. The results in Figure 26 show the distributions of the injected CO_2 (in gas/unit area) over time, which includes the status of preinjection, at the end of CO_2 injection (25 years cumulative time), 25 years of postinjection (50 years cumulative time), and 75 years of postinjection (100 years cumulative). These simulation results indicate that the CO_2 may reach both of the gas pools within the 100-year period. After these simulations were run, a quantitative RA was performed. The RA indicated that the possibility of contacting the nearby gas pools required further geological characterization between the proposed injection locations and the gas pools. In addition, an alternative injection location farther to the west would help reduce this risk of contacting the gas pools. An alternative injection location, combined with integrated activities such as additional site characterization, drilling a second test well, new seismic acquisition data, and model validations, is needed to reduce the potential risk around the c-61-E location or the proposed location (c-47-E) farther to the west (Gorecki and others, 2013).

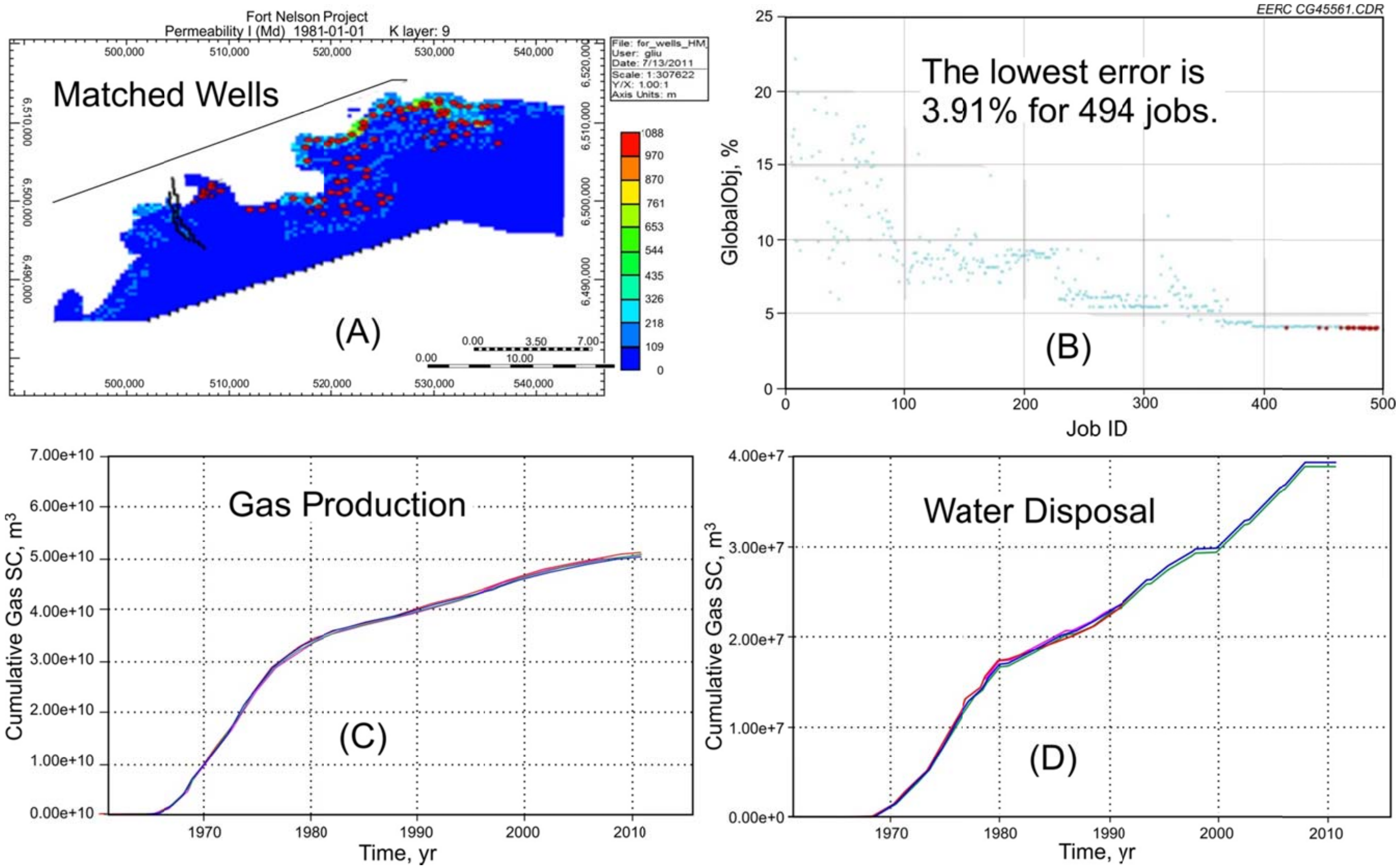

Figure 23. History-matching results: A) matched 92 wells, B) global objective function error for 494 simulation jobs, C) cumulative gas production, and D) cumulative water disposal based on the top five "best"-matching cases (SC is standard conditions: 15.5°C, 101.25 kPa) (Gorecki and others, 2013).

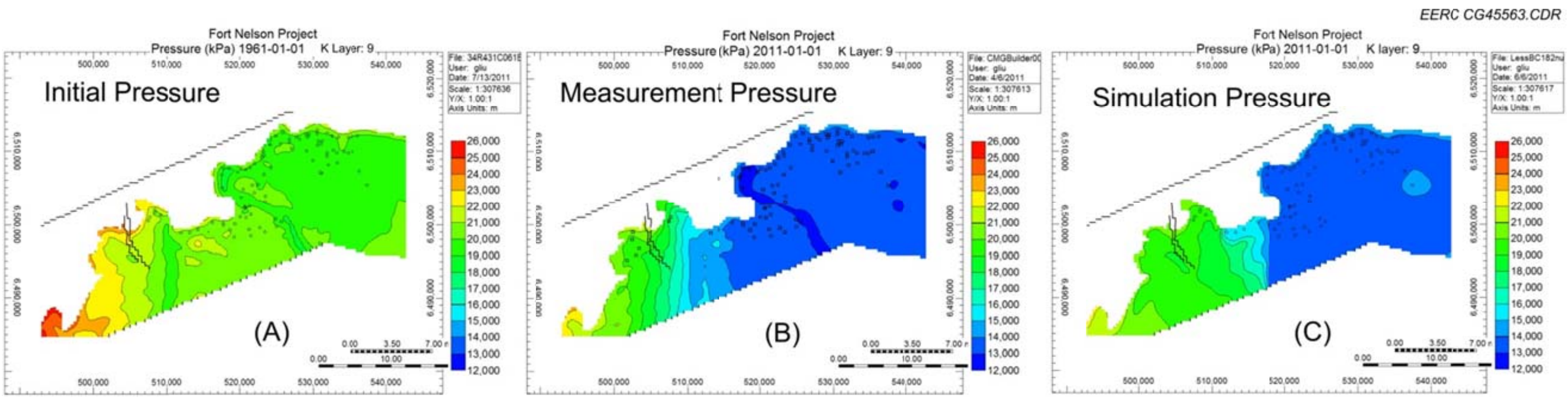

Figure 24. Pressure distributions: A) initial pressure distributions, B) measured pressure distributions (January 2011), and C) matched pressure distributions (Gorecki and others, 2013).

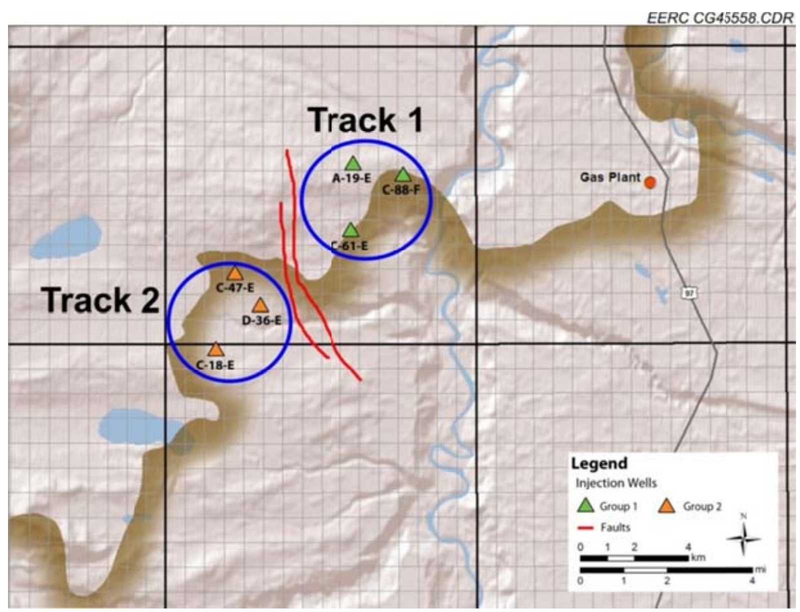

Figure 25. Location of tracks and injection wells (Gorecki and others, 2013).

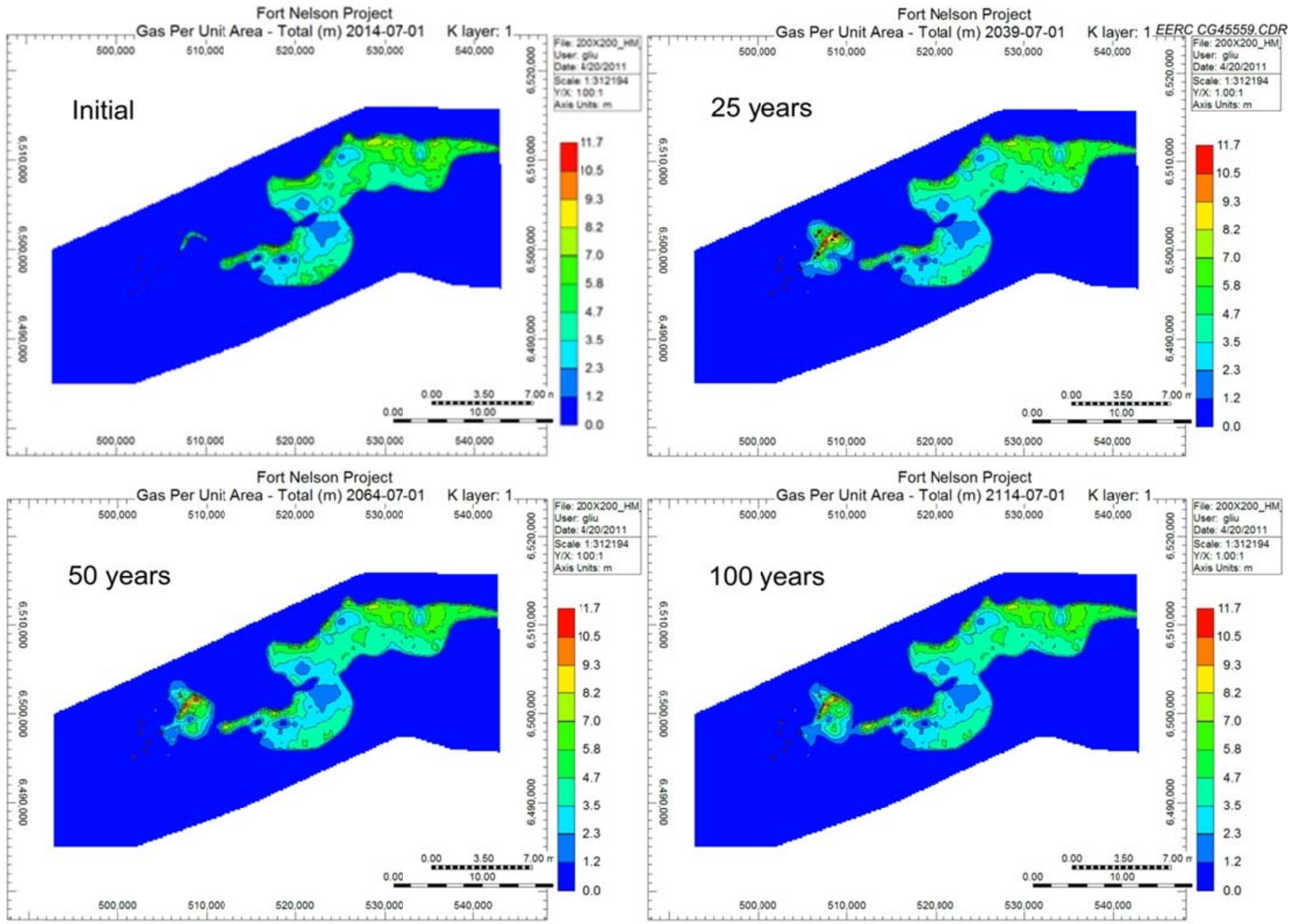

Figure 26. CO_2 movement over time around Test Well c-61-E (Gorecki and others, 2013).

Alternative CO_2 Injection Location

The results of initial RA around Test Well c-61-E suggested that the injection location should move 5–10 kilometers southwest, around the proposed well, c-47-E (Track 2), to avoid communication between injected CO_2 and gas pools (Figure 25). In Track 2, 1.1 MMm^3/day (40 MMscf/day) was injected into three wells, including the new proposed well, c-47-E, for a combined sour CO_2 injection rate of 3.4 MMm^3/day (120 MMscf/day) for 25 years, with an additional 75 years of postinjection simulation, for a total of 100 years simulated (Gorecki and others, 2013).

The predictive simulation results in Track 2 indicate that the CO_2 plume does not contact the nearby gas pools during the 100-year simulation period (top of Figure 27). When comparing the two injection and risk tracks, injection in and around Track 2 greatly reduces the likelihood of sour CO_2 contacting either gas field; however, there is greater uncertainty in the geology in that region because there are limited seismic or well data. In Track 1, there is a possibility that sour CO_2 may contact one or both of the nearby gas fields before the end of the productive life of either field. However, there is still a large degree of geologic uncertainty between Track 1 and the gas fields. In addition, the BHPs based in the injection wells in Track 2 are 1000 to 3000 kPa lower than the BHPs in the Track 1 injectors (Figure 28). While Track 1 shows a lower overall risk profile, there is a large degree of geologic uncertainty in that region, which requires further investigation (Gorecki and others, 2013). Additional cases were also run on both tracks with 50 years of injection. Figures 29 and 30 show the positions of these predicted plumes relative to the geographic features of the Fort Nelson study area.

The static and dynamic modeling in the Fort Nelson CCS Project plays a crucial role in predicting the movement of sour CO_2 in the reservoir, informing the RA, and helping to define and develop the MVA plan. The proposed dynamic modeling workflow, along with the integrated approach to site characterization, modeling, and RA, can lead to a more targeted, site-specific, and technically and economically feasible MVA plan and CCS project.

Both injection locations (Track 1 and Track 2) appear to have sufficient capacity to accommodate the target injection volumes. However, current knowledge suggests that Track 2 may be a better option (compared to Track 1) because the injected sour CO_2 has a more contained CO_2 footprint and does not contact the adjacent gas pools during the 100-year simulation period. In addition, the injection well BHPs in Track 2 were predicted to be 1000 to 3000 kPa lower than the injection well BHPs in Track 1. Overall, Track 2 has a lower risk profile; however, the collection of 3-D seismic data and the drilling of an additional well in the vicinity of Track 2 are necessary to determine whether or not the geology is suitable for the injection of 3.4 MMm^3/day (120 MMscf/day) for 25 years.

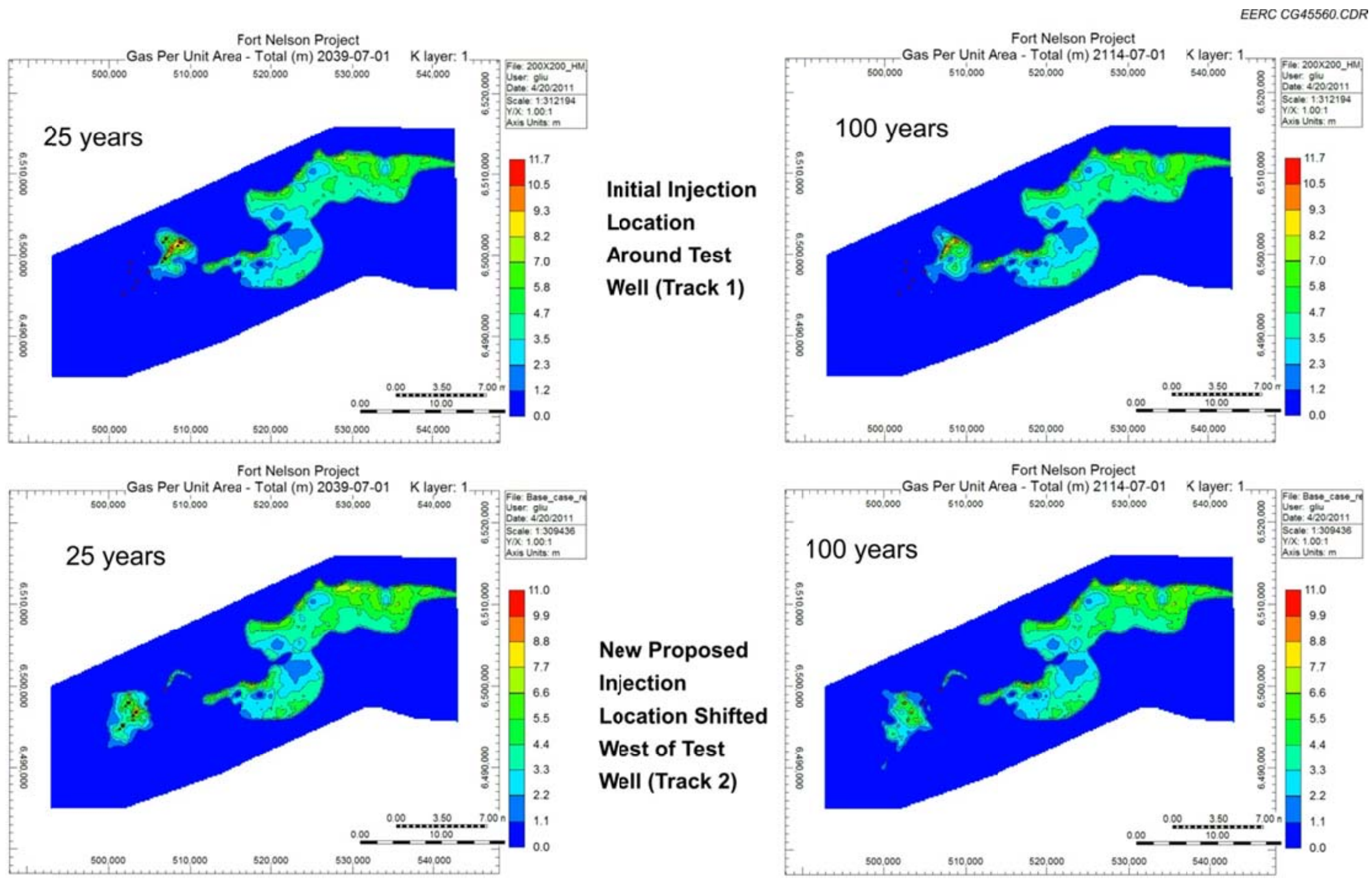

Figure 27. Gas per unit area over time for two tracks. Track 1 is based on Test Well c-61-E after history matching (top), and Track 2 is based on Well c-47-E (bottom) (Gorecki and others, 2013).

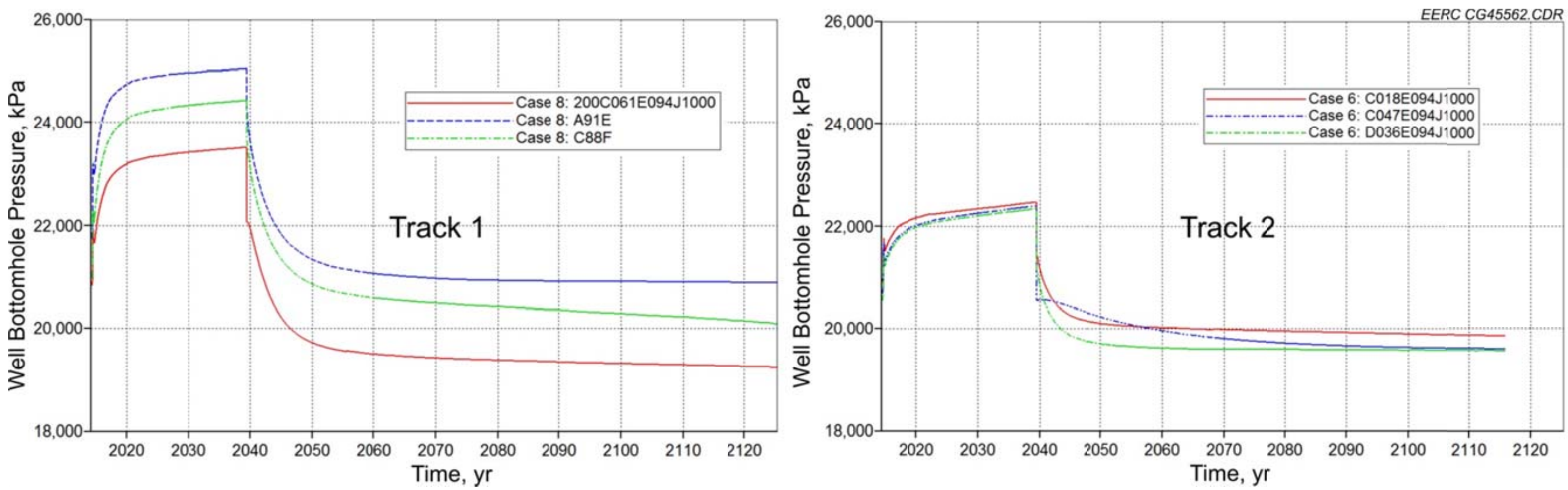

Figure 28. BHP plots by each injection well, in tracks. Track 1 is on the left, and Track 2 is on the right (Gorecki and others, 2013).

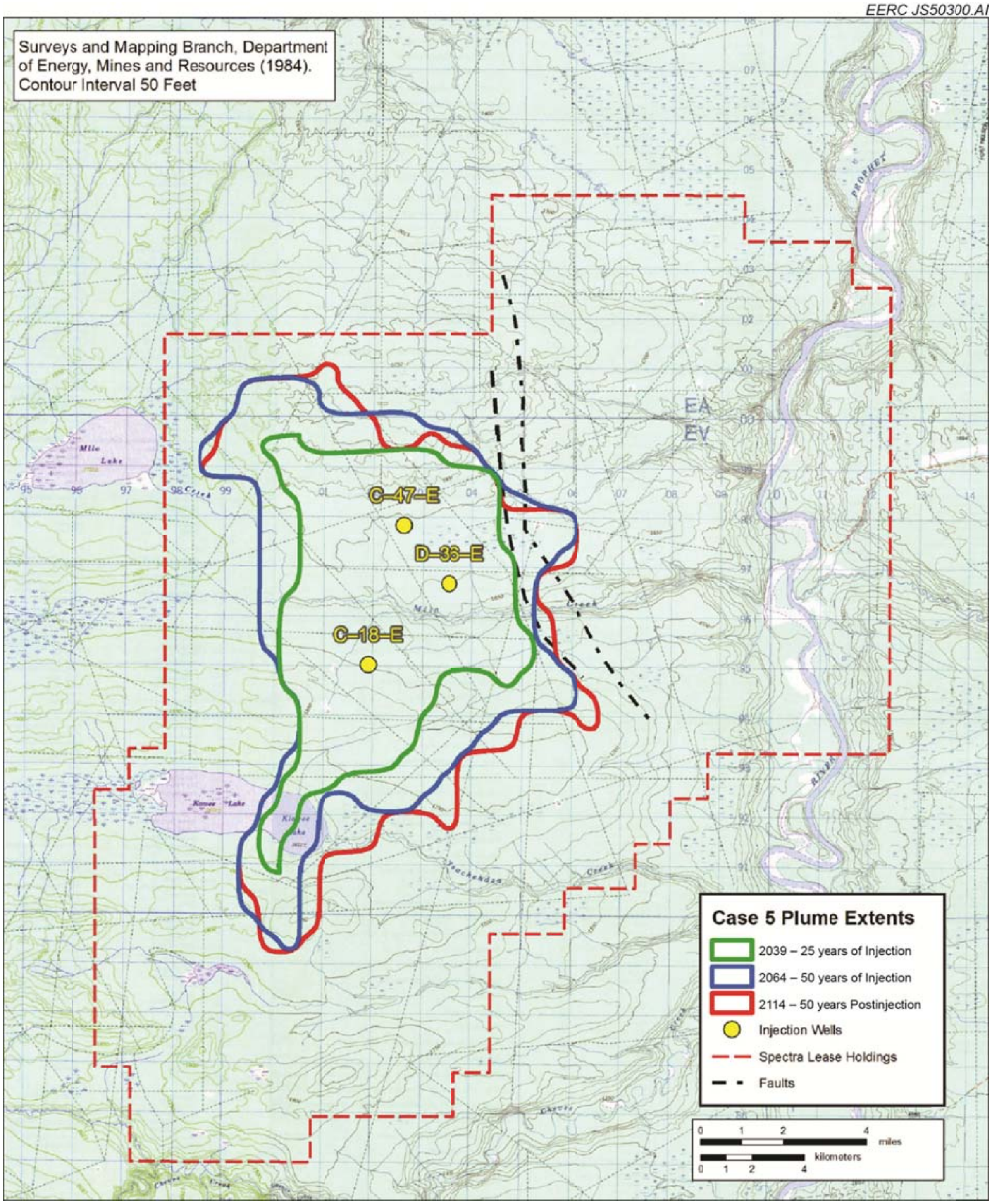

Figure 29. Map of predicted plume extents over time for one of the potential injection scenarios – Case 5, three injection wells located west of the graben structure, injecting a total of 3.4 Mm^3/day (120 MMscf/day) for 50 years, starting in 2014.

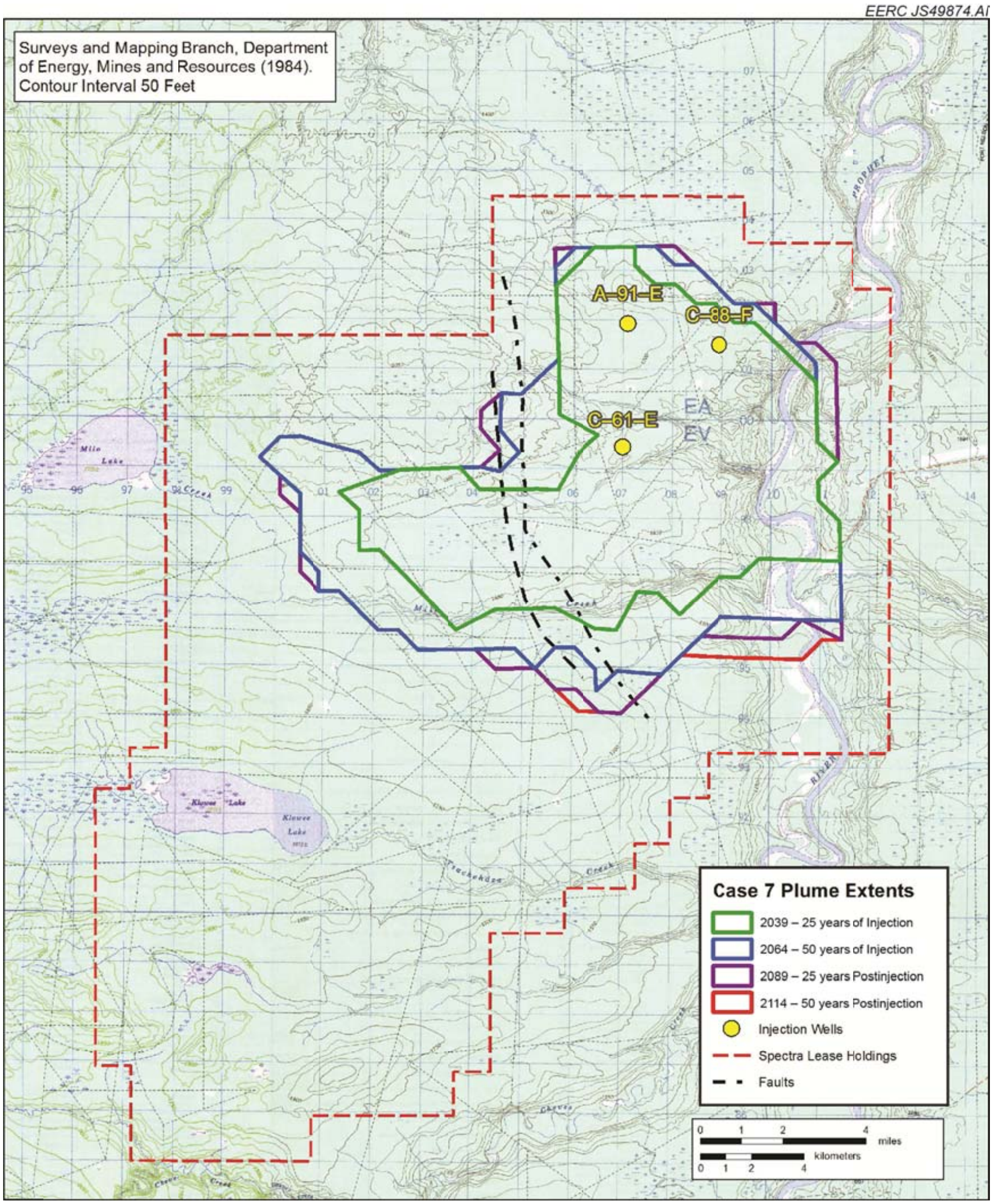

Figure 30. Map of predicted plume extents over time for one of the potential injection scenarios – Case 7, three injection wells, including c-61-E, located east of the graben structure, injecting a total of 2.5 million tonnes/year for 50 years, starting in 2014.

GEOMECHANICAL MODELING FOR FORT NELSON

In parallel with the development of the reservoir model, the EERC embarked on the development of an uncoupled companion model to address the geomechanical system effects of sour CO_2 injection at the Fort Nelson site. However, these geomechanical modeling efforts were not considered to be essential to the feasibility study, therefore none were completed in their entirety, and their integration into the petrophysical reservoir model of the site was not attempted. The geomechanical modeling efforts were initiated using a clipped, or scaled-down, petrophysical reservoir model, which accounted for the necessary sour CO_2 plume extension while eliminating the complexity of the full-scale reservoir model. The clipped model was produced by reducing the existing full-scale petrophysical reservoir model to the extent that it is volumetrically sufficient for sour CO_2 plume occupation, as predicted by dynamic simulations (i.e., 2030 to 967 km^2). As currently configured, the clipped model includes only one injection well and only one of the Clarke Lake Slave Point gas pools, i.e., A or B. This clipped model was used for uncoupled (and potentially coupled) numerical modeling of geomechanical effects. Should SET decide to implement CCS at Fort Nelson, these modeling activities would likely be reinitiated and brought to completion. A brief summary of the status of these companion modeling activities is provided in the remainder of this section.

Geomechanical Model Development

The EERC initiated a geomechanical model development effort to evaluate the reservoir geometry and internal architecture of the Middle Devonian carbonate formations. The intent was also to evaluate the overlying and surrounding cap rock as well as the underlying aquifer systems that may provide reservoir support. This modeling effort will permit the evaluation of the likely nature of pressure dissipation within the reservoir and surrounding reef complex system as well as the movement of displaced brine both within the injection formation and, potentially, into other proximal brine-saturated formations (i.e., the Keg River and Slave Point Formations).

The EERC developed a geomechanical model development plan for the Fort Nelson site that consisted of the following five steps:

1. Data collection from well logs and core analysis
2. Construction of a 1-D MEM (mechanical earth model)
3. Construction of a 3-D MEM using the 1-D MEM and site-specific seismic data
4. Performance of coupled simulation and analysis for the reservoir system
5. Performance of a cap rock integrity analysis using the coupled simulation model

A schematic of this development process is provided in Figure 31. To date, the EERC has completed the first two steps of this development effort, as discussed here.

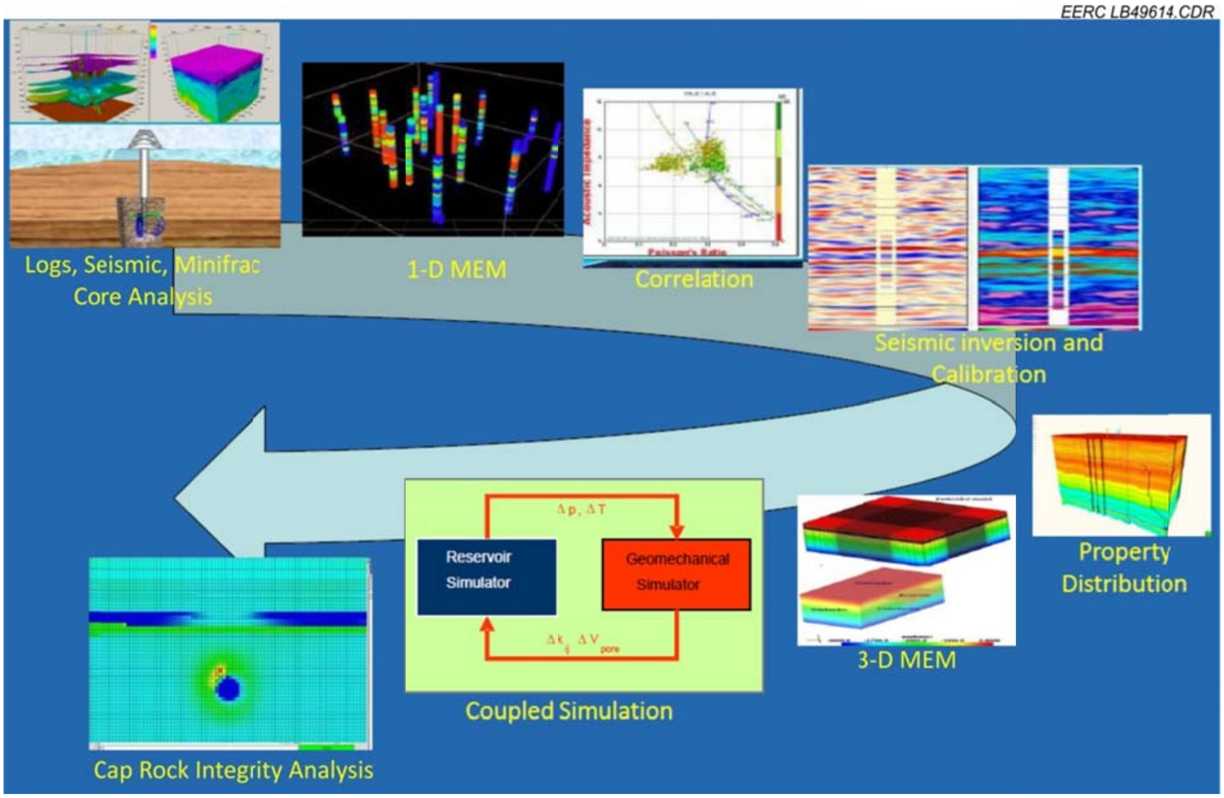

Figure 31. Geomechanical modeling process (modified from Khan and others; 2010, Zandi and others, 2010a, b).

Data Collection and Core Analysis for Geomechanical Modeling

The data for the construction of the 1-D MEM for the Fort Nelson project came from the well logs of the exploratory well, c-61-E; analysis of the c-61-E core; and available seismic data with the location of c-61-E. The available log data for Well c-61-E came from a variety of sources such as gamma ray logs, spontaneous potential logs, caliper logs, density logs, and vertical seismic profiles (VSPs). These log data were analyzed in Schlumberger's Techlog™ for lithology analysis, pore pressure prediction, in situ stress analysis, and rock elastic properties. The core testing data were generated on two samples from the Muskwa shale cap rock. With these data for the cap rock, Young's modulus and Poisson's ratio, as well as the compressive strength and other rock characteristics, were estimated as presented in Tables 6–8.

In addition to the c-61-E well logs and the testing results for the Well c-61-E cores, other publications that focused on the area near the Fort Nelson project site were also relied on as sources for additional regional data (Chou and others, 2011; Hawkes and others, 2005).

Table 6. Summary of Ultrasonic Velocities and Dynamic Elastic Parameters

Sample No.	Depth, m	Confining Pressure, MPa	Bulk Density, g/cm^3	Ultrasonic Velocity		Dynamic Elastic Parameter			
				Vp, km/sec	Vs, km/sec	Young's Modulus, GPa	Poisson's Ratio	Bulk Modulus, GPa	Shear Modulus, GPa
MP1	2045.67	17.93	2.73	4.51	2.79	50.49	0.19	27.32	21.18
MP2	2048.11	17.93	2.76	5.26	3.28	70.06	0.18	36.80	29.62

Table 7. Summary of Triaxial Compressive Tests

Sample No.	Depth, m	Confining Pressure, MPa	Compressive Strength, MPa	Static Young's Modulus, MPa	Static Poisson's Ratio
MP1	2045.67	17.93	173.97	34,780	0.22
MP2	2048.11	17.93	231.53	44,915	0.27

Table 8. Results of Mohr–Coulomb Failure Analysis

Sample No.	Depth, m	Confining Pressure, $Pc = \sigma_3$, MPa	Differential Stress, $\sigma_1 - \sigma_3$, MPa	Compressive Strength, σ_1, MPa	Slope on σ_1 vs. Pc	Unconfined Compressive Strength, MPa	Angle of Internal Friction, deg.	Coeff. of Internal Friction	Cohesion, MPa
MP2	2048.11	2.07	83.5	85.5					
		10.00	191.1	201.1	9.20	80.7	53.5	1.35	13.3
		17.93	213.6	231.5					

Construction of 1-D MEM

The foundation of a 3-D geomechanical model is a 1-D MEM. The EERC constructed a 1-D MEM capable of assessing the stress regime and rock properties along an individual well at the Fort Nelson project site, i.e., c-61-E. The 1-D MEM was built using Techlog to analyze the well log data, which were then imported into Schlumberger's Petrel™ for visualization. Based on the availability of the data, the rock mechanical properties and stress states along the monitoring well were estimated for the interval from 2503 to 2530 m. To address the region above this interval, additional data from the rock in this region are required. The properties of the 1-D MEM are ready for incorporation into a fieldwide 3-D MEM.

Future Geomechanical Modeling

The EERC did not construct a 3-D MEM, nor were coupled simulations and analysis of the reservoir system or a cap rock integrity analysis using the coupled simulation model performed. However, a fieldwide 3-D MEM is ready for construction based on the existence of the 1-D MEM, the availability of vintage well data, and the recent availability of 3-D seismic data at the Fort Nelson project site. Should this be done, the coupled simulation process could then be performed between a reservoir simulator and a geomechanical simulator. More specifically, the EERC would couple Lawrence Berkeley National Laboratory's reservoir simulator TOUGH2™ and Itasca's geomechanical simulator FLAC3D™ to perform the future geomechanical simulations at the Fort Nelson project site. The goal of these reservoir geomechanical simulations would be to predict the stress and strain variations in the reservoir formations and the cap rocks and estimate the leakage potential for CO_2 during the CO_2 injection process.

The Role of Thermal Modeling

The thermal modeling of sour CO_2 injection into a saline formation is an integral part of any reservoir-modeling effort, including the Fort Nelson project. During sour CO_2 injection, changes can take place that could affect the temperature of fluid injection, fluid enthalpy, heat losses due to friction and gravitation effects, and the temperature conditions around the injection well. These changes in the local thermal conditions could potentially result in 1) fracturing within the reservoir or cap rock, 2) loss of injectivity and permeability from the Joule–Thomson effect, 3) loss of injectivity and permeability from induced geochemical reactions, and 4) wellbore sour CO_2 flow and phase change.

The EERC planned to conduct thermal modeling for the Fort Nelson site with the intent of using a preliminary clipped thermal model and a full-scale petrophysical reservoir model to conduct dynamic simulations of temperature redistribution within the reservoir and evaluations of thermal effects on the geological storage system. This modeling would have been performed in several stages, including 1) the development of 1-D and 2-D homogeneous and heterogeneous site-specific and parameter-sensitive models followed by 2) reservoir-scale coupled 3-D reservoir models. However, this effort was preempted by project schedule considerations. As such, no thermal modeling has been conducted as of the writing of this report.

Modeling Summary

With optimization and model validation, the current dynamic model, which is based on the Version 3 static geologic reservoir model, shows a good match with the historical data, especially gas and water production, water disposal, and regional pressure distribution in the gas pools. A good history match for these data has provided improved confidence in the modeling of the geologic characteristics in the project area.

The dynamic predictive model results indicate that the geology within the Fort Nelson project study area is very conducive to the long-term storage of CO_2. The simulation results also validate prior assumptions of excellent reservoir injectivity, lateral plume spreading, and the potential effectiveness of alternative injection techniques for both injection locations in and around c-47-E and c-61-E. All of the tested injection sites show sufficient storage capacity for injection of the desired amount of CO_2 in the model area. However, the area in and around c-47-E demonstrated the greater capability for storing the desired amount of CO_2 within the model area because there is no contact with the gas pools within the 100-yr simulation period and the maximum BHPs are below 23,000 kPa for all cases after history matching.

To further confirm the evaluations conducted by the EERC, two primary recommendations are suggested to be included in future modeling and simulation studies, should they be done: 1) more geologic information for the injection region, especially in the region of c-47-E and the transient region between gas pools and injection area, are needed to confirm the existence of adequate reservoir rock and the presence or lack of any low-permeability barrier (or fault) that was artificially introduced into the dynamic model and 2) integration of the critical physical phenomena such as geochemical reactions, geomechanical behaviors, and geothermal effects is needed into the dynamic model to provide a more comprehensive understanding of the sink–seal system of the Fort Nelson project site.

In general, the results of these modeling activities have served as a critical component of the RA program and MVA planning for the Fort Nelson project. Specifically, the modeling results play a primary role in the identification of risks related to the injection operation, reservoir management, potential leakage pathways, and potential impacts to neighboring gas fields. By predicting the movement of the sour CO_2 plume and the propagation of pressure away from potential injection sites, the modeling results provide much of the basis for finalizing site location decisions and developing a cost-effective MVA program. Finally, the modeling also provides insight and direction for conducting the next iteration of site characterization activities (i.e., exploratory wells, seismic surveys, injection tests, etc.), which will ensure the development of more realistic future models.

RISK ASSESSMENT AND MANAGEMENT

An effective risk management framework has several components, including RA, risk treatment, communication, and monitoring. RA consists of identifying the relevant site-specific risks, estimating their frequency (i.e., the likelihood that the risk may occur), and estimating their severity (i.e., the impact of a risk on environment, health and safety, finance, public perception, and/or legal/regulatory). The frequency and severity of each risk are then used to map the risk ranking such that risk may be classified from low- to high-ranking risks. Once the risks have been assessed and mapped, the high-ranking risks must be managed using one of four options: acceptance, transference, avoidance, or mitigation. Finally, the risks must be monitored to ensure that they have been successfully managed following the pursuit of one of these options. A monitoring plan based on the results of the RA helps ensure the project is safe by monitoring the site-specific risks of concern while also limiting project costs by ensuring that money is not spent on monitoring for risks that may not be significant to the project (i.e., a risk-based monitoring strategy). Additionally, communication with both internal and external stakeholders about risk is an essential part of gaining confidence and trust in a project.

The risk management process used for the Fort Nelson project for managing its subsurface technical risks is illustrated in Figure 32 and complies with International Organization for Standardization (ISO) 31000, an international standard for risk management. The risk management methodology described was designed to integrate the ISO 31000 framework with existing SET risk management processes, practices, and risk tolerance standards. The remainder of this section briefly discusses each step of the general risk management process.

Figure 32. Risk management framework and process used for the potential Fort Nelson project (modified from ISO 31000).

To date, the RA for the Fort Nelson project has been implemented in two phases: Round 1 RA and Round 2 RA. The Round 2 RA, which updated the Round 1 RA, was completed following the collection of additional site and laboratory data and the conduct of additional simulation modeling. In addition to reexamining the subsurface technical risks, the Round 2 RA also included a risk evaluation of an alternative sour CO_2 injection point (i.e., c-47-E). The alternative injection point was selected to reduce the likelihood that the injected sour CO_2 would impact the Clarke Slave Point A and B gas pools before the end of their productive life. A summary of the risk management framework that was applied as part of these efforts as well as the results of both rounds of the RA are provided in this section.

Context

This first step in setting up a risk management system for a project requires establishing the context for the RA through the development of a risk management policy. For the Fort Nelson project, a risk management policy was created that defined the risk management process guidelines, including the risk criteria. The risk criteria were developed through interviews with both internal and external project stakeholders and combine the individual concerns and risk tolerance levels of the stakeholders with existing SET RA criteria. Throughout the interviews, it was determined that SET has preestablished strict levels of risk acceptability. This low-risk tolerance is reflected in the parameters that were used for the RA, i.e., frequency and severity ranking of individual risks.

Risk Assessment

According to the Canadian Standards Association, RAs shall include a comprehensive risk identification process; a technically defensible risk analysis; and a transparent, traceable, and consistent risk evaluation process that aims to avoid bias (Canadian Standards Association, 2012). The level of rigor applied to RA will be dictated by the nature of available information and the degree of knowledge about risk scenarios that is required to enable stakeholders to make informed decisions at each stage of the project. Generally speaking, each pass of the risk management process will enhance the detail in the attendant round of RA until each of the identified risk scenarios is thoroughly assessed.

Risk Identification

Risk identification for the Fort Nelson project involved the determination of which risks were relevant to the project. It was done using a functional analysis, coupled with a failure mode and effects analysis (FMEA) and yielded a preliminary risk register, which is a list of project-relevant risks. A workshop was then held with several experts with technical expertise and knowledge of the project who together validated the risk register as containing only those risks that specifically applied to the target injection site of the Fort Nelson project.

Risk Estimation

The risk estimation phase of the RA consisted of an analysis of the risks in the risk register and the development of a quantitative ranking of their overall risk to the project. The risks were rated using a combination of the frequency of occurrence and the potential severity of the resulting impact. The risk criteria developed as part of the risk management policy are key components of this step.

A common challenge of technical RAs is linking the technical risks, such as CO_2 leakage, to a strategic severity (e.g., public perception). For the Fort Nelson project, this was dealt with by using a table of physical consequences that allows a physical rating of the risks and transfer matrices that connect the physical consequences to the strategic severity levels. The transfer matrices were developed with international project stakeholders, and they reflect the specific concerns of those stakeholders. A round of risk estimation workshops and meetings was held where experts used the results of modeling and simulations, along with the risk criteria that were developed specifically for the project, to assign a frequency of occurrence and physical consequence rating to each risk following the workshop; the criticality score (frequency + severity) was calculated for each risk using the transfer matrices to convert the estimated physical consequences into severity.

Risk Mapping

The first- and second-round RAs developed risk maps for each of the project-specific risks. A risk map visually presents the risks so that they can be easily compared. It allows users to quickly tell how significant a risk is for the project and compare it to the other project risks that were evaluated. For the Fort Nelson project, two reference periods were identified as being relevant for these RAs: 50 and 100 yr. The 50-yr periods correspond to the estimated period of CO_2 injection to which is added an additional 50 yr of potential SET liability after injection ceases, yielding a total 100-yr period. While the liability period has not yet been formally established by the regulatory agencies, it is expected that the government will assume liability after a certain period, and 50 yr was estimated as the duration of this period for this iteration of the RA. Risk maps were created for both the 50- and 100-yr time frames.

First-Round Risk Assessment Results

The Round 1 RA included the identification of the potential technical risks originating from or otherwise associated with the subsurface, including any wells in the Fort Nelson project study area that may be directly or indirectly related to the Fort Nelson project (i.e., sour CO_2 injection wells, monitoring wells, and nearby gas production wells). Although the risks are technical in origin, they can significantly impact several aspects of the project and SET in areas such as financial, environment, and health and safety. An extensive list of potential impacts was considered in this RA.

Of the 27 risks that were assessed in the Round 1 RA, 14 were classified as serious or extreme criticality risks to the project as currently proposed. These risks can be summarized as falling into the following four general categories:

- Sour CO_2 contamination of two currently producing gas pools (i.e., Slave Point A and B) in overlying formations that are in close proximity to the CO_2 injection location currently under consideration.

- Pressure changes in the target reservoir resulting from the injection of sour CO_2 that may propagate through the geologic system and affect the production of natural gas from Slave Point A and B or the water disposal operations in the Slave Point B pool.

- Loss of injectivity in the target reservoir due to local pressure buildup as a result of lower-permeability areas within the reservoir and/or near-well clogging of pore space caused by geochemical or geomechanical interactions.

- Insufficient storage volume in the target reservoir either because of regulatory permit limitations or reservoir characteristics (e.g., lack of connection to the regional saline formation).

Several points should be considered when interpreting the results of the first-round RA:

- The Fort Nelson project was in an exploratory phase during the completion of the Round 1 RA. For this reason, the geologic, geochemical, and geomechanical properties of the project area and the risks associated with the Fort Nelson project are not yet completely understood. The Round 1 RA and risk mapping directly reflect the incomplete understanding of the CO_2 storage system that exists at this early stage of project development.

- The first-round RA was based on very preliminary data from a single test well and no laboratory results. By drilling a second test well, acquiring additional seismic data, and getting the complete results from the laboratory work, a much better representation of the geologic model and potential risks can be achieved.

- The model used to perform the Round 1 RA was based on a simplified model that was not originally intended to completely describe the subsurface. The RA results are limited by the constraints of this model.

- Because of the inherent uncertainty in the geological data for the first-round RA, the experts who were asked to rate the identified risks were unable to reach a consensus for some of the risks because of the lack of field data and supporting laboratory work. As a result, instead of rating a risk with a single value, a range was given to represent the uncertainty. This uncertainty is consistent with the exploration phase of the project and will likely be reduced as more data become available and future RAs are completed.

- For the Round 1 RA, it was decided to take a “worst-case scenario” approach. This approach was conservative, and many of the higher risks would likely be ranked lower if a “more probable” approach had been taken.

Risk management is an iterative process. The results of this first-round RA serve as a guide for the development of more information and strategies that will reduce the risk. Data that were not available at the time of the Round 1 RA were generated, yielding, among other things, an updated geologic model (Petrophysical Reservoir Modeling section of this report) that provided updated input into the Round 2 RA.

However, although the first-round RA was based on incomplete data, several important conclusions were drawn from the results:

- Even while using a conservative, worst-case scenario approach, many risks were ranked very low and were determined to be acceptable. As such, it is likely that they will be ranked even lower in a more realistic scenario.

- The impact of an injectivity loss on the operation of FNGP and SET's customer relationships would be a major issue if the risks remain untreated. This risk can be reduced with a properly defined injection strategy, that is, number of wells, location, injection rate, and extra injection capacity (redundancy).

- The vicinity of the current test site to the adjacent operating gas pools increases the potential of the risk of interference or contamination of these pools. If not properly understood and treated, this could lead to major issues with customers and regulators. With a more detailed assessment, as well as exploring an alternative storage site, it is likely that these risks can be reduced.

- Since this RA was generated during the exploratory phase of the project, there are significant gaps in the current level of understanding of the subsurface. These gaps result in uncertainty in the risk ratings; however, this uncertainty will likely be reduced by gathering more data and performing additional rounds of modeling, simulation, and RA.

- Although the results of the first-round of RA show there may be some potentially higher risks, those risks can likely be reduced by relatively simple treatment options such as acquiring more site-specific data, gathering more information about specific risks, performing additional laboratory tests on site materials, and performing additional modeling and simulations.

- The inclusion of new data in a second-round RA will support the development of a project-specific MVA plan to monitor the critical risks in the most efficient and cost-effective manner, thereby further reducing the risks.

Based on this first-round RA, it was recommended that more knowledge of the overall geologic system should be gathered by implementing the following activities:

- Drilling a new exploration well to the west of c-61-E
- Acquiring new seismic data
- Performing additional site-specific laboratory tests
- Conducting specialized analyses and modeling (e.g., geochemical)

By using this additional knowledge, a more realistic model (Version 3) of the geology was developed, and further simulation work can be done to help understand the potential evolution and migration of the injected sour CO_2. Additional, more realistic RAs can then be performed to provide a more accurate picture of the project's critical risks. Treatment strategies, which could include altering some aspect of the project, e.g., the CO_2 injection strategy, could then be implemented to reduce the frequency of occurrence, lower the potential consequences, or avoid the targeted risk. Finally, a comprehensive MVA plan could be developed to monitor the system and document that the risks are being managed. The combination of an effective risk management framework and an MVA plan will help ensure that the technical subsurface risks are successfully identified and controlled over the lifetime of the project.

Second-Round Risk Assessment Results

The second-round RA updated the first-round RA for the Fort Nelson project. Using additional modeling/simulation results and data that had been collected since the completion of the first-round RA through December 31, 2010, the second-round expanded the first-round RA by addressing the relative project risks associated with two sour CO_2 injection locations: a new proposed drilling location (c-47-E) and the original test well location (c-61-E). The alternative injection location (c-47-E) is located approximately 5 km west of the original test well location and was chosen to reduce the likelihood that the sour CO_2 injection would impact the Clarke Lake Slave Point A and B gas pools before the end of their productive life, as suggested by the results of the first-round RA at the c-61-E injection location. In addition, the second-round RA incorporated Monte Carlo simulation into the risk profile assessment to develop a probability distribution for individual risks rather than a discrete (i.e., single) value. The previously defined reference periods of 50 yr of injection and 50-yr postinjection were retained as the basis for this subsurface technical RA.

Risk Register

As part of the Round 2 RA, a revised project-specific risk register was created, which included 31 potential individual risks. This risk register was built upon the risk register of the first-round RA with modifications.

These changes resulted in a net addition of four project-specific risks to the first-round RA for a total of 31 project-specific risks. These 31 project-specific risks of the Round 2 RA can be grouped into five general classifications:

- Capacity: a loss of CO_2 storage with respect to the initial storage estimate, resulting in an inability to inject the proposed 120 million tons of CO_2 in 50 years
- Containment: leakage to the atmosphere, usable groundwater, or nearby natural gas pools
- Injectivity: percent of lost CO_2 injectivity with respect to the nominal injection rate
- Seismic: induced seismicity due to injection of sour CO_2
- Strategic: potential strategic risks to SET

In a manner consistent with the first-round RA process, each risk was examined by SET and its subject matter experts, who then assigned frequency (probability of occurrence) and severity (impact of a risk on environment, health and safety, finance, public perception, and legal/regulatory compliance) scores to each of these risks. However, these assignments were based on geologic data, laboratory results, and reservoir simulation modeling that became available after the first-round RA through December 31, 2010. Wherever possible, direct measurements and/or simulations were used to evaluate risks, providing more quantitative and less subjective estimations of the risks.

Ranking of Individual Risks

The rank of each risk was determined using a similar rubric as defined in the first-round RA: (rank = frequency + severity), where scales of 1 to 5 were established for both of these parameters. Figure 33 presents the generic risk-ranking grid that was generated from the use of this rubric, which results in risk rank values for each individual risk, ranging anywhere from 2 (i.e., frequency = 1 and severity = 1) to 10 (i.e., frequency = 5 and severity = 5). As shown in Figure 28, the risk rank values were grouped into four zones, characterized by the following qualitative descriptions of risk:

- Risk rank value = 2 to 4: low, or negligible, risk
- Risk rank value = 5 to 6: transition zone, warranting close monitoring
- Risk rank value = 7 to 8: moderate risk
- Risk rank value = 9 to 10: high risk

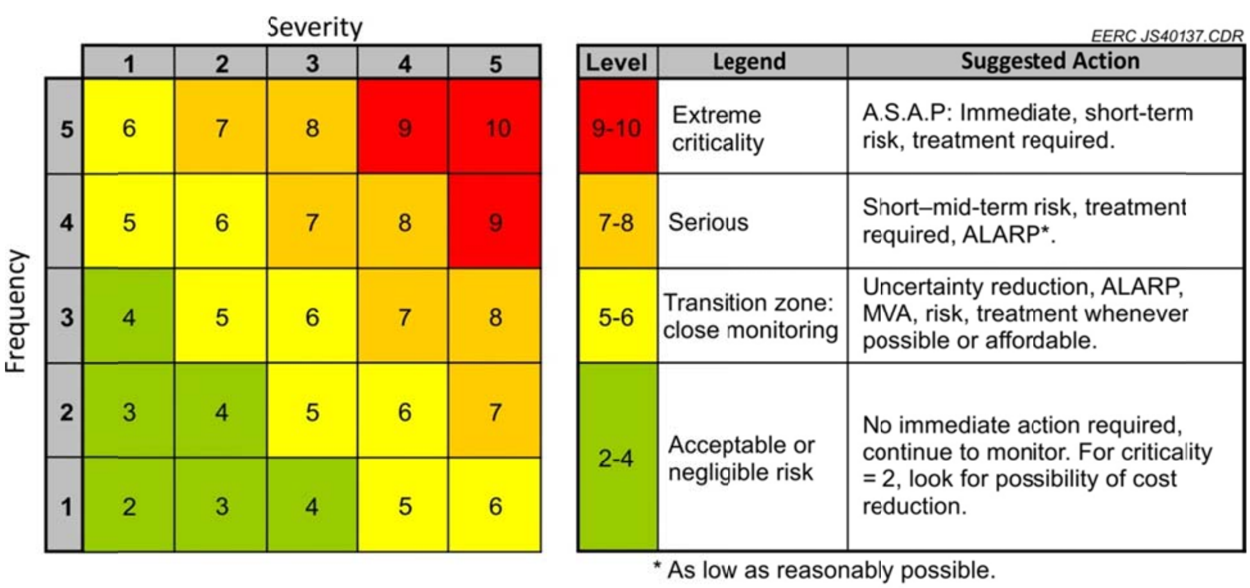

Figure 33. Generic risk-ranking grid used to map all project risks in the second-round RA (2010) (Gorecki and others, 2012).

Risk Mapping and Assignment of High-Rank Risks

A high-rank risk was defined as a risk with a risk rank value of 7 or greater. As shown in Figure 33, this definition included those risks in both the moderate- and high-rank risk zones. This information was used to conduct a coarse preliminary assessment of the overall project risk associated with each of the defined risk tracks by comparing and contrasting the number and makeup of these moderate- to high-rank risks. Four risk maps were created for Risk Track 1 (Location c-47-E) and Risk Track 2 (Location c-61-E). The risk maps represent the following conditions:

- Minimum frequency and severity values for the reference period of 50 yr
- Maximum frequency and severity values for the reference period of 50 yr
- Minimum frequency and severity values for the reference period of 100 yr
- Maximum frequency and severity values for the reference period of 100 yr

Project Risk Profile Assessment

To fully characterize the risk profile of the dual-risk tracks for the Fort Nelson project, as a whole, a Monte Carlo simulation was performed. This simulation required the ranking of the individual project-specific risks to be redefined as the product of the frequency of the risk and its severity rather than the sum of these two values. It also required that the frequency and the severity of a project-specific risk be expressed as probability distributions rather than as discrete values. By taking this approach, it is possible to more quantitatively capture the uncertainty of these variables in the ranking of each project-specific risk and to combine the individual risk ranks to yield an overall risk profile for the project. To that end, the frequency and severity scales were modeled as probability distributions for each project-specific risk, using the minimum and maximum values of the ranges provided by the expert panel as the bounds of the distribution. Using these distributions, the Monte Carlo simulation was conducted to generate a probability distribution of project risk-ranking scores that represented the sum of the rank values (i.e., sum of products of frequency × severity) for all of the 31 individual risks. As previously noted, the probability distribution of these project risk-ranking scores permitted a more direct quantitative comparison of the project risk profiles for the dual-risk tracks (i.e., comparison of the overall project risk profile between the injection location, c-61-E, and c-47-E).

Comparison of Project Risk Profile Scores for Dual-Risk Tracks

Figure 34 presents the histograms of the project risk profile scores that were generated by the Monte Carlo simulation for Risk Track 1 (i.e., the new proposed drilling location at Well c-47-E) and Risk Track 2 (i.e., the original test well location at Well c-61-E). This figure presents the number of simulations (out of a total of 1000) that yielded the project risk profile score shown on the x-axis of the graph. As depicted, it is clear that the distribution of the project risk profile scores for Risk Track 1 lie to the left, i.e., are generally less than the distribution of the scores for Risk Track 2.

Figure 35 presents the same data as in Figure 29 but in a cumulative probability plot. Based on this representation of the data, it can be seen that the project risk profile score for Risk

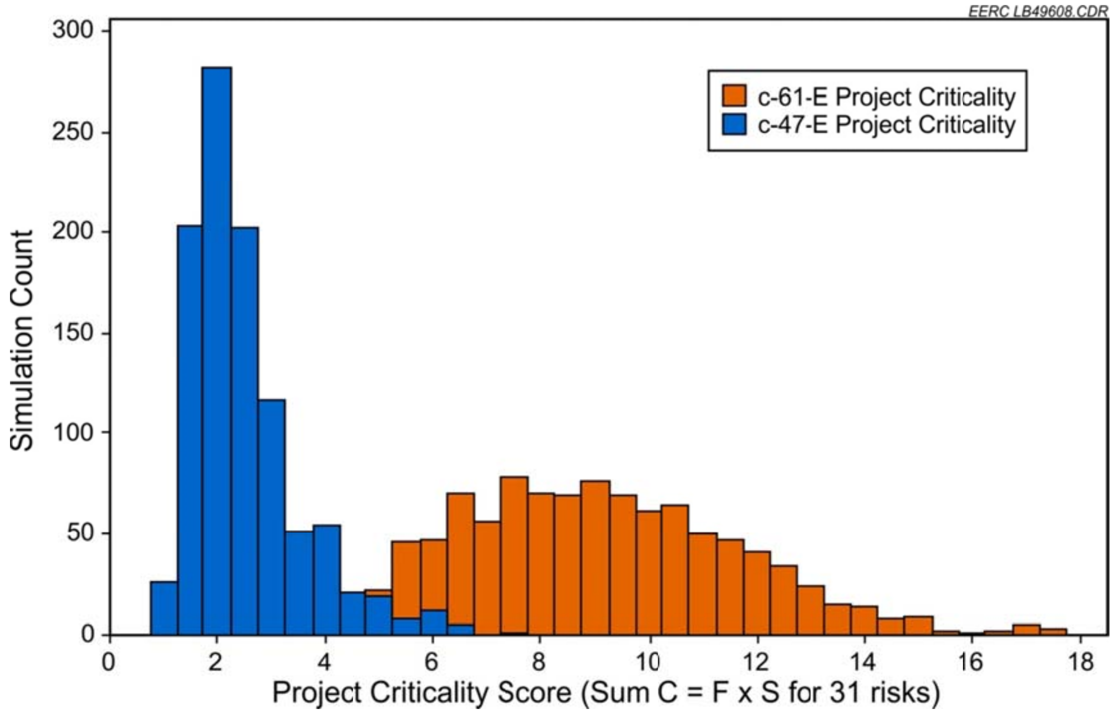

Figure 34. Histograms of the total project risk profile score for the new proposed drilling location (c-47-E [Risk Track 1]) and the original Round 1 RA test well location (c-61-E [Risk Track 2]) based on Monte Carlo simulation.

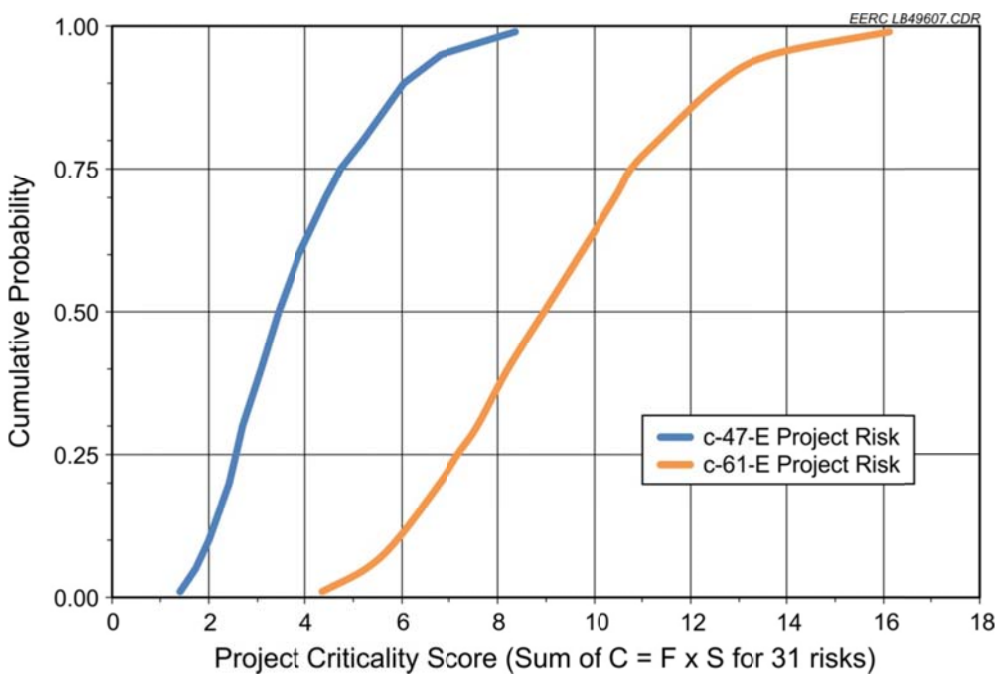

Figure 35. Cumulative probability distribution of total project risk profile score for the new proposed drilling location (c-47-E [Risk Track 1]) and the original Round 1 RA test well location (c-61-E [Risk Track 2]) based on Monte Carlo simulation.

Track 1 will be less than 7 nearly 100% of the time, whereas a similar score from Risk Track 2 is expected only 30% of the time. These results suggest that there is a significantly lower overall project risk associated with Risk Track 1 versus Risk Track 2. In other words, by adaptively modifying the injection location from Well c-61-E to a location 5 km west at proposed Well c-47-E, the overall project risk decreases. However, it should be noted that increased geological uncertainty exists around the c-47-E injection location and should be further evaluated through additional characterization (drilling and testing a new well and acquiring 3-D seismic over this area).

Risk Assessment Conclusions

The combination of risk mapping and Monte Carlo simulations for each of the 31 project-specific risks of the Round 2 RA yielded the following conclusions:

- Overall project risk is lower for the new proposed drilling location (Risk Track 1: c-47-E) than the original Round 1 RA test well location (Risk Track 2: c-61-E), largely because of the decreased likelihood of impacting the Clarke Lake Slave Point A and B gas pools.

- Impacts to Clarke Lake Slave Point A and B gas pools are more likely at the original test well location (Risk Track 2: c-61-E) than the new proposed drilling location (Risk Track 1: c-47-E), which is located more than 5 km to the west of c-61-E and west of the graben fault.

- Leakage of CO_2, H_2S, or formation brine to usable groundwater and leakage of CO_2 or H_2S to the atmosphere at either injection location are considered unlikely.

- Seismic risks at either injection location are considered unlikely, as the Fort Nelson project study area is located in a region of extremely low natural seismicity. Also, injection pressures are expected to remain well below pressures that may cause microseismicity.

- Strategic risks are higher at the original test well location (Risk Track 2: c-61-E) than the new proposed drilling location (Risk Track 1: c-47-E) because of potential permitting restrictions that would exist as a result of potential impacts to the Clarke Lake Slave Point A and B gas pools.

- Capacity and injectivity concerns remain higher at the new proposed drilling location (Risk Track 1: c-47-E) than the original test well location (Risk Track 2: c-61-E) because of the lack of site-specific subsurface data at this location.

Based on the results of this RA, the highest-priority data collection/data analysis efforts for the next iteration of the characterization, modeling, simulation, and project RA include the following:

- Drilling of an exploratory well and collection of additional data near the proposed alternative CO_2 injection location (Risk Track 1: c-47-E). A sensitivity analysis of the overall project risk associated with this new injection location (c-47-E) showed that the collection of additional data in and around this injection location (c-47-E) would improve the understanding of reservoir permeability and storage capacity in this area, e.g., geophysical data, well logs, etc., and has the potential to substantially decrease the overall project risk.

- Collection of 3-D seismic data in the area over/around the alternative injection location (Risk Track 1: c-47-E) to better understand potential fault distribution and subsurface structure.

- Conduct of geomechanical and geochemical laboratory tests of the reservoir rock collected from the new injection location (Risk Track 1: c-47-E). These additional laboratory tests would focus on an assessment of the potential for fracturing and/or plugging of the reservoir during sour gas CO_2 injection, both of which are important to gas storage and containment.

- Conduct of wellbore integrity laboratory and field tests. Data on relevant industry experience related to wellbore integrity and fundamental failure modes in acid gas environments need to be gathered and reviewed to identify critical data gaps. If warranted, both laboratory (e.g., acid gas exposure tests) and field (e.g., field pressure tests, various downhole evaluations of abandoned wells such as cement bond logs, and targeted side coring of abandoned wells in acid gas disposal sites) tests should be conducted to address these data gaps, with the ultimate goal of assessing the impact of acid gas on the wellbore cement and casing and evaluating the potential for gas leakage from the gas storage site.

- Conduct of predictive simulations using an updated site geologic model. As appropriate data become available, the current version of the site petrophysical reservoir model can be updated and additional predictive simulations performed to reevaluate those risks related to pressure buildup, containment, and brine/sour CO_2 migration.

While this updated second-round RA attempted to move away from a worst-case analysis using Monte Carlo simulations, the risk analysis is still in its early stages of development and would benefit from additional data regarding the nature of risk frequency and severity probability distributions. The data collected and/or generated from the above activities will serve as input into the next update of this RA, continuing the iterative RA process. These iterations will continue to reduce the uncertainty of the analysis and improve the prediction of CCS project risks.

MVA PROGRAM

Overview

CCS technology is still in an early stage of development; therefore, it is important to demonstrate its capability to permanently store the captured CO_2 in the subsurface. As a result, monitoring technologies are needed to track the changes occurring in the subsurface as a result of CO_2 injection over long periods of time. Furthermore, the integration of these technologies into a coherent and site-specific MVA plan will ensure that the collected information allows the operator to apply the appropriate mitigation actions should a deviation from the injection plan occur. DOE assigned the following objectives to MVA plans associated with CO_2 geological storage operations (U.S. Department of Energy National Energy Technology Laboratory, 2009, 2012):

- Improve the understanding of storage processes and confirm their effectiveness.

- Evaluate the interactions of CO_2 with formation solids and fluids.

- Assess environmental, safety, and health (ES&H).

- Evaluate and monitor any required remediation efforts should an out-of-zone migration occur.

- Provide a technical basis to assist in legal disputes resulting from any impact of implementing geologic subsurface CO_2 sequestration technologies (groundwater impacts, seismic events, land use impacts, mineral resource impacts, etc.).

The regulatory authorities of British Columbia require that a proper site-specific MVA plan be prepared for the Fort Nelson project. SET and the EERC elected to use a risk-based approach to define the MVA strategy. This means that the MVA plan will be derived from the RA of the storage project and be primarily focused on the early detection of the occurrence of the most critical risks and their mitigation.

The EERC also established additional objectives for the Fort Nelson project's MVA plan:

- Cost-effectiveness: Since the Fort Nelson project is not a research and development project, but a demonstration of a commercial-scale application of a geologic subsurface sequestration technology, it is imperative that a cost-effective MVA plan be developed, consisting of proven monitoring technologies.

- Minimal disruption of operations: The MVA plan should by no means hamper the commercial storage operations; rather, it should support them. Therefore, the use of technologies that had the potential to disrupt the storage operations was avoided.

Current Status of MVA Activities

The EERC has initiated the development of a risk-based, site-specific MVA plan for the Fort Nelson project, which includes a preinjection monitoring program consisting of surface-, shallow subsurface-, and deep subsurface-monitoring components. These initial MVA efforts are summarized in Appendix A.

A site-specific, risk-based monitoring plan is designed to mitigate negative impacts and reduce uncertainties by iterative application of monitoring and risk analysis (Canadian Standards Association [CSA], 2012). The trend in recent years among MVA planners has been to integrate site characterization, modeling and simulation, RA, and monitoring strategies into an iterative process to produce robust, broadly defensible MVA plans. It is important to note that the PCOR Partnership and SET activities were conducted to examine the feasibility of a potential CCS project at Fort Nelson. Many steps remain before SET makes a go/no-go decision regarding implementation of a CCS project at Fort Nelson (i.e., design phase). Therefore, the current MVA planning for a potential Fort Nelson project is considered to be hypothetical.

The Fort Nelson draft hypothetical MVA plan includes monitoring elements that cover the surface, near-surface, and deep subsurface environments. Surface water sampling from lakes and streams, shallow groundwater wells, and soil gas-monitoring stations in the vicinity of the deep monitoring and injection wells would allow for monitoring any impacts to the surface and shallow subsurface. The MVA technology matrix for Fort Nelson would include geophysical logs, wellbore integrity monitoring, 3-D seismic surveys, and a variety of downhole instruments (e.g., pressure and temperature sensors) and remote sensing tools. MVA technologies would be deployed at locations selected according to their surface accessibility and spatial relationship to the predicted plume. The timing of MVA events would be planned according to technical need and cost-effectiveness. For instance, operational parameters such as injection rates and reservoir temperature and pressure conditions would be monitored continuously. Surface and shallow subsurface monitoring, such as soil gas and shallow groundwater sampling and analyses, would be conducted seasonally or annually. Deployment of deep reservoir-monitoring tools such as well logs or seismic surveys would be conducted in time steps that range from annually to every 5 years, depending on the technology and the stage of the operation (early-stage deployment would be more frequent than later stage). Figure 36 illustrates the deployment of monitoring technologies at Fort Nelson according to zones (surface, shallow subsurface, and deep subsurface). The locations of potential monitoring activities in relationship to predicted plume geometries for the Case 5 injection scenario (2.5 million tonnes injected per year, for 50 years, on the west side of the graben) are shown in Figure 37.

One aspect of MVA that is sometimes underappreciated is the effect that geography and climate can have on implementation. At Fort Nelson, those effects are significant. The climate of the Fort Nelson area includes long, cold winters. The landscape is characterized by a poorly drained taiga terrain, much of which is only accessible by ice roads constructed in the winter. This limits the work season for heavy equipment to only a few months each year. In nonwinter seasons, much of the area can only be accessed by small all-terrain vehicles or helicopters. These

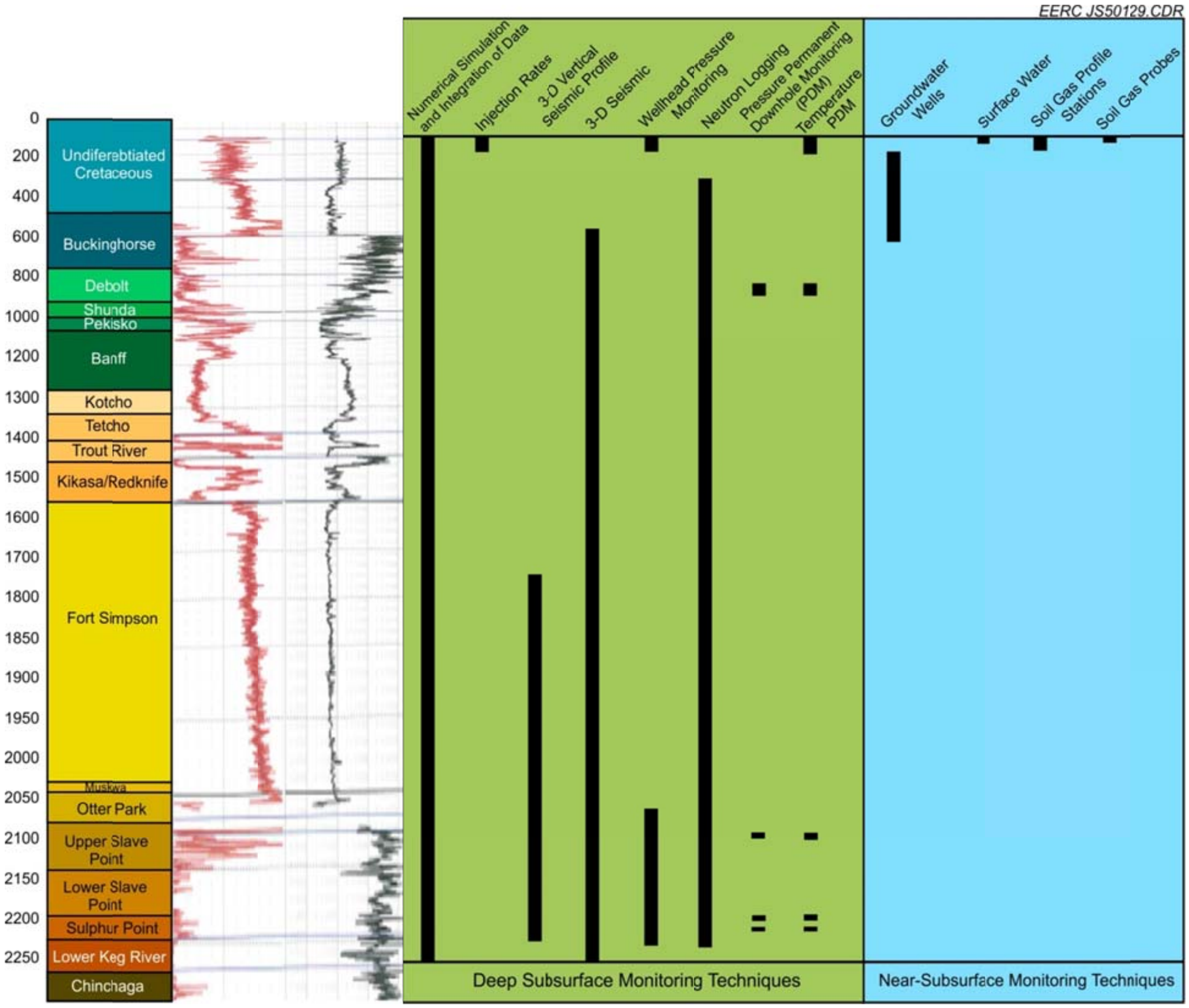

Figure 36. Hypothetical monitoring technology deployment by zone for a potential Fort Nelson project (Sorensen and others, 2014a).

conditions will limit the number and dictate the location of MVA technology deployment sites. However, while the climate and terrain present challenges with respect to site access and operations, the fact that the oil and gas industry has been able to cost-effectively explore for hydrocarbons and construct and maintain wells and their associated infrastructure for decades under those difficult conditions indicates that MVA at Fort Nelson can also be done. The key to overcoming the challenges presented by climate and terrain at Fort Nelson will be thorough, careful planning and project execution in the field that applies the lessons learned by the local oil and gas industry. The hypothetical MVA plans developed for a potential Fort Nelson project took into account those challenges and industry experience.

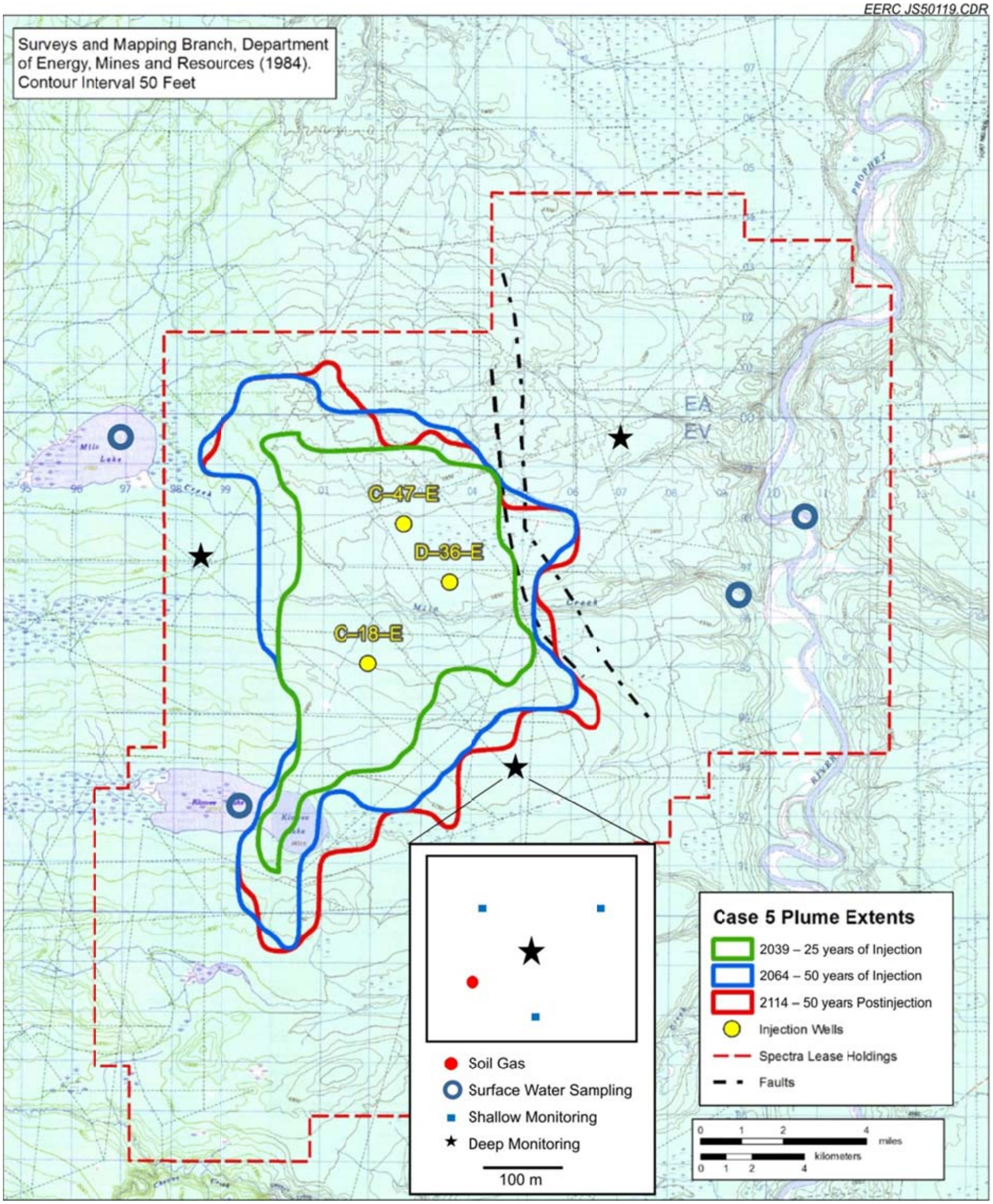

Figure 37. Map of predicted plume extents over time for one of the potential injection scenarios (Case 5) and locations for monitoring activities (Sorensen and others, 2014a).

CSA Standard for Geological Storage of Carbon Dioxide and Comparison to Fort Nelson Project Efforts

In October 2012, CSA released a standard for geological storage of CO_2 entitled "Z741-12 Geological Storage of Carbon Dioxide." The standard was developed by CSA's Technical Committee on Geological Storage of Carbon Dioxide, which is a joint Canada–U.S. Technical Committee. This committee included 38 individuals with a broad range of experience in government, academia, and the oil and gas industry. This standard, by itself, does not have the force of law unless it is officially adopted by a regulatory authority (Canadian Standards Association, 2012). However, it is possible that the CSA standards, in total or in part, could be adopted or referred to by British Columbia regulatory authorities. With this in mind, the Fort Nelson project activities and the draft hypothetical MVA plan were compared to the CSA standard. A brief summary of the CSA draft standard is provided as follows.

The CSA standard can be considered to be comprehensive in that it provides detailed descriptions of practices and procedures for essentially all aspects of a CCS project. Specifically, the CSA standard provides guidance for what it considers to be the six key elements of a CCS project: 1) management systems; 2) site screening, selection, and characterization; 3) risk management; 4) well infrastructure development; 5) monitoring and verification; and 6) cessation of injection. The following is a brief breakdown of the topics covered by the CSA standard within each key project element:

- Management Systems – This section includes standards for the project operator's roles and responsibilities, project stakeholders, continuous improvement, and project definition. Standards for project boundaries (operational, physical, and organizational), management principles, planning and decision making, resource management, communications, and documentation are also presented.

- Site Screening, Selection, and Characterization – This section presents standards for screening, selecting, characterizing, modeling, and assessing a location for geological storage of CO_2. Site characterization and assessment are further broken down into standards for the characterization of geologic and hydrogeologic properties of the storage reservoir and confining strata, baseline conditions for geochemical and geomechanical parameters, and existing wells in the vicinity of the proposed project. Standards are also presented for the creation of static geologic models, dynamic flow modeling, geochemical modeling, and geomechanical modeling.

- Risk Management – This section provides a very thorough presentation of standards for risk management as applied to a CCS project. Standards are presented for all aspects of risk management, including risk planning, assessment, identification, analysis, evaluation, treatment, documentation, communication, and consultation with stakeholders. This section also includes recommendations for the principles and processes associated with each aspect of risk management.

- Well Infrastructure Development – This section provides guidance on well construction materials, design, construction schemes, corrosion control, and operation and maintenance. The section on well construction includes guidance on drilling, completions, workovers, abandonment, and restoration.

- Monitoring and Verification – This section presents standards for MVA planning, including program design, procedures, and practices. This section also presents a set of MVA specifications that CSA considers to be required and a set of specifications that are considered to be recommended.

- Cessation of Injection – This section includes guidance for developing plans for the postinjection and closure periods of a CCS project. This section also includes a description of the qualification process for the postinjection and closure periods.

The CSA standard for geological storage of CO_2 can be used for different purposes, not only in Canada but internationally as well. One potential scenario is that government agencies may officially incorporate the CSA standard, as a whole or in part, into their regulatory process. There are also other scenarios by which nongovernment stakeholders could use the CSA standard as a benchmark by which CCS projects can be judged both within and outside of the legal system, even in jurisdictions that do not officially adopt the standards. With this in mind, and because the CSA standards are the most detailed and thorough standards of their kind developed by a North American organization, particular attention was paid to comparing the Fort Nelson project efforts to the three aspects of the CSA standard that are most applicable to the efforts to develop an MVA plan: 1) site screening, selection, and characterization; 2) risk management; and 3) monitoring and verification. While management systems, well infrastructure development, and closure are equally important elements of safely and effectively conducting geological storage of CO_2, the PCOR Partnership efforts at Fort Nelson did not cover those aspects, so they were not included in the comparison.

The CSA standard presents criteria for site screening, site selection, site characterization and assessment, and modeling for characterization. There are 13 criteria that address the technical, legal, and regulatory aspects of site screening. Site selection is addressed by 29 surface and subsurface criteria. Over 60 criteria aimed at site characterization and assessment are presented for geologic, hydrogeologic, geochemical, geomechanical, and well characterization. Modeling for characterization is covered by approximately 100 criteria that are devoted to static modeling, flow modeling, geochemical modeling, and geomechanical modeling. A comparison of the CSA standards to efforts conducted by SET and the PCOR Partnership shows that those efforts clearly address all of the site selection, characterization, and modeling criteria. In fact, in a majority of the categories, the Fort Nelson efforts to date exceed many of those CSA standards. A generalized summary of that comparison is shown in Figure 38 and a more detailed comparison is provided in Appendix B.

With respect to RA, the CSA standard includes approximately 120 specifications for risk management. Areas of risk management that the CSA standard addresses include objectives, context, risk management planning, RA, planning and review of risk treatment, review and documentation, and risk communication and consultation (Canadian Standards Association,

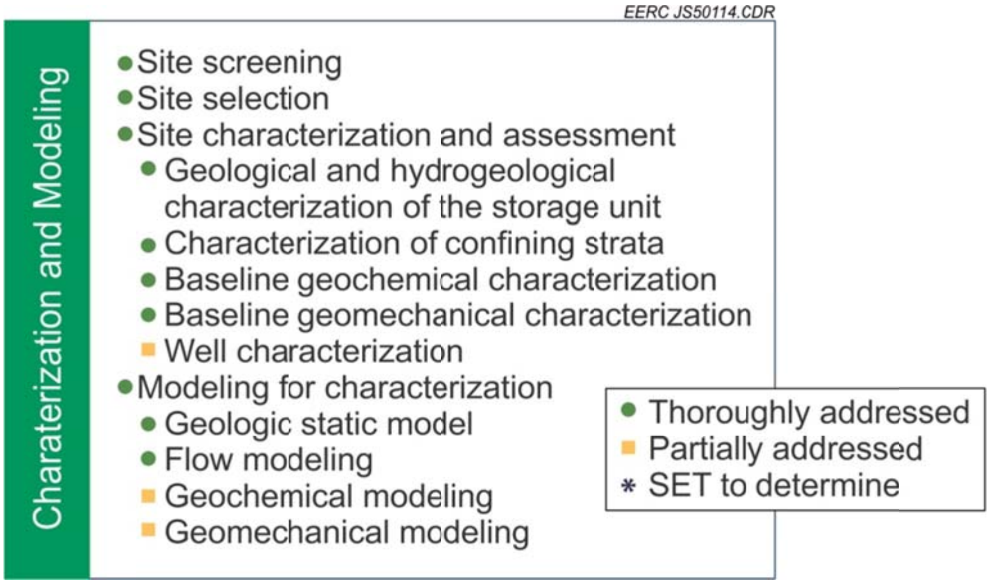

Figure 38. Generalized summary of Fort Nelson characterization and modeling compared to CSA standards (Sorensen and others, 2014a).

2012). The Fort Nelson RA efforts address all of those criteria and, in many cases, go beyond the CSA specifications. Figure 39 presents a generalized summary of that comparison, and Appendix B provides a more detailed comparison.

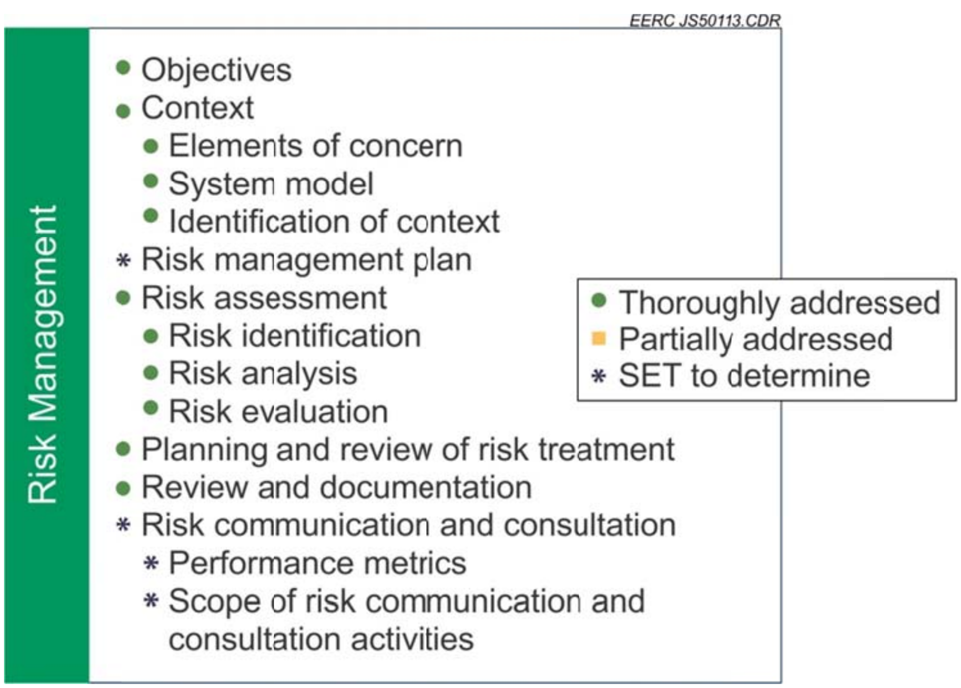

Figure 39. Generalized summary of Fort Nelson risk management compared to CSA standards (Sorensen and others, 2014a).

Regarding MVA, the CSA standard presents many monitoring and verification program-required specifications. These specifications range from the relatively straightforward and mundane, such as planned injection rates and total mass of CO_2 to be stored, to complex subjects that require multidisciplinary study. An example of the latter is a specification which states that the MVA plan is required to include "the risk-based ranking of scenarios that have the potential to cause significant health, safety, or environmental impact or to negatively affect storage performance.... This description should encompass the link between monitoring and verification design and any updated RA results in compliance with the RA criteria…."

Generally speaking, while the CSA standard enumerates in significant detail the expectations for the types of information that are required and recommended in an effective MVA plan, the standard does not prescribe the use of specific technologies in either the acquisition of baseline data or the monitoring of injected CO_2. CSA states that "the purpose of monitoring and verification is to address health, safety, and environmental risks and assess storage performance. Monitoring, verification, and accounting activities support a risk management strategy that enables an assessment of storage performance and provides confidence that greenhouse gas reductions are real and permanent." This passage is relevant because it is an example of CSA's tendency to directly link RA and management with the development of an effective MVA plan. The linkage of MVA to risk analysis is a theme that runs strongly throughout the CSA standard document.

CSA states that the MVA program must provide information on 19 different categories. Some of the categories are further broken down into subcategories, with each requiring its own specific information. This results in a total of approximately 80 criteria that must be addressed by the MVA planning activities. Major categories for which standards are enumerated include MVA purpose, program periods (i.e., preinjection, injection, closure, and postclosure periods), program objectives, and program design. The CSA standards offer brief, generalized guidelines with respect to MVA purpose and program periods.

MVA program objectives are addressed by 12 criteria, while over 60 criteria are presented for MVA program design. The program design section includes 28 required specifications and 23 recommended specifications. A detailed description of how each of the elements of the hypothetical Fort Nelson MVA plan compare to all of these criteria and specifications is beyond the scope of this paper. However, a comparison of the CSA standards for monitoring and verification to the MVA approach and technology matrix being considered for a hypothetical Fort Nelson project indicates all of the required specifications and a majority of the recommended specifications would be adequately addressed. The challenges associated with limited site accessibility because of climate and terrain may preclude Fort Nelson CCS operations from fully implementing many of the recommended MVA protocols and technologies but should not prevent the application of those that are required under CSA standards. A generalized summary of that comparison is provided in Figure 40.

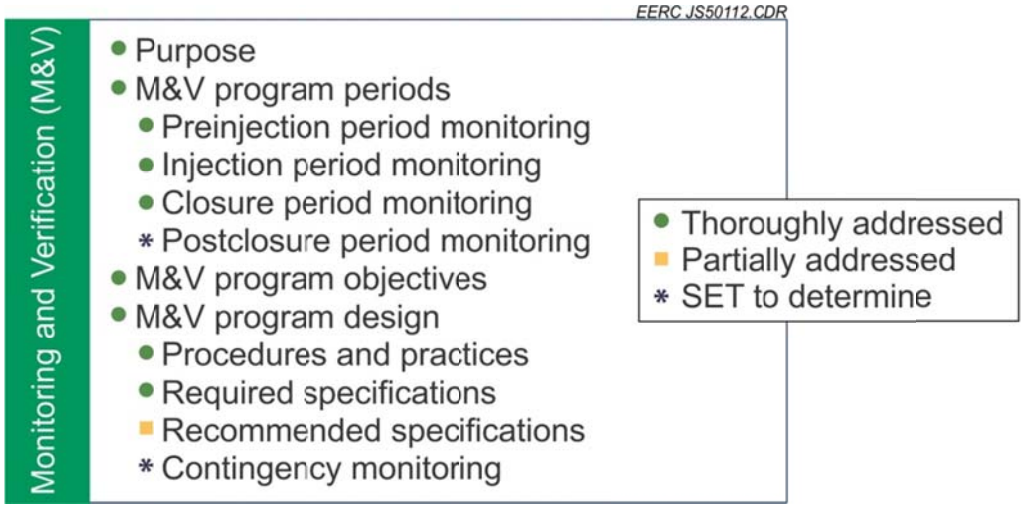

Figure 40. Generalized summary of Fort Nelson MVA planning compared to CSA standards (Sorensen and others, 2014a).

CONCLUSIONS

This report summarizes the work performed on the Fort Nelson project by the PCOR Partnership. It reflects the integrated approach to project implementation that has been developed over the course of the PCOR Partnership since 2003. This integrated approach consists of four primary technical elements: site characterization, modeling and simulation, RA, and monitoring. These technical elements are executed in series, with continuous feedback loops that permit modifications to the approach based on the interim findings generated. This approach is particularly well-suited for the adaptive management process that is required to implement projects of the size and complexity typical of commercial-scale geologic carbon storage projects. Although not demonstrated in its entirety because of the delays in project implementation that plagued the commercial partners of the Fort Nelson project, two nearly complete cycles of the integrated approach feedback loop were essentially completed, with several cycles of the feedback loop demonstrated between the site characterization and modeling and simulation elements of the approach (Sorensen and others, 2014a). Based on this project experience, a streamlined technical protocol has been developed that can be applied to any site where subsurface geologic sequestration is under consideration as part of a carbon reduction management strategy. This report, combined with the reports and presentations that have been created as part of this project, provides both a road map and the technical details for the implementation of the PCOR Partnership strategy for CCS projects involving subsurface geologic sequestration of CO_2 and sour CO_2.

Key Observations and Lessons Learned

- Detailed studies of the geologic conditions of both sinks and seals in an area being considered for large-scale CCS are critical for CCS project site selection, operational design and implementation, RA, and MVA planning. The geological studies of the deep carbonate saline formations of the Presq'uile reef complex in the Fort Nelson area indicate that it has sink and seal conditions that make it an exceptional candidate location for large-scale CCS. The potential sink formations include areas with excellent injectivity characteristics. Also, the storage capacity of the Devonian carbonate formations in the Presq'uile reef complex has been estimated to range from 137 million to 244 million metric tons, which is sufficient to support the full anticipated formation CO_2 emissions of FNGP for several decades. The extremely low permeability, geomechanical competence, and tremendous thickness (>500 m) of the overlying Muskwa and Fort Simpson shale formations mean that those shales will serve as excellent seals for storage in the Devonian carbonates.

- The carbonate formations at Fort Nelson exhibit properties that make routine characterization both challenging and potentially misleading. For example, carbonates are deposited in a wide variety of depositional environments leading to heterogeneities in rock fabric, texture, and geochemistry, which, in turn, can lead to widely variable distributions of porosity and permeability. This makes detailed rock characterization from multiple wells and the correlation and integration of those data with other data sets (e.g., seismic surveys, well logs, hydrogeological studies) critical to reducing the uncertainty associated with injectivity and storage capacity estimates. It also underscores the importance of conducting iterative characterization activities that build upon one another and reduce the uncertainty inherent in geologic interpretations.

- Because of the high value of rock testing data and the implications of those data to developing realistic reservoir models, core collection, handling, preservation, and analysis must be planned and executed with the utmost care. Careful evaluation of historical geologic data from the area being evaluated is necessary to plan for the collection of core (e.g., predicting depths of potential seal and sink formations for sampling purposes).

- Geochemistry studies are necessary to predict the potential for geochemical reactions that could adversely affect CO_2 injectivity and storage capacity. Geochemistry studies should include laboratory tests of potential target sink and seal formation materials (e.g., cuttings, core, fluids) in the presence of the anticipated gas injection stream (95% CO_2 and 5% H_2S in the case of FNGP) under reservoir conditions. Geochemical modeling should also be done to predict the potential long-term reactivity of the injectate stream and sink–seal rocks and fluids. Screening-level geochemistry studies using materials relevant to a potential Fort Nelson project indicate that the geologic system (rocks and fluids) will likely have relatively low reactivity with the FNGP injection stream.

- Geomechanical studies are essential to determine the integrity of the seals and their ability to contain CO_2 over geologic periods of time. The Fort Nelson site has been demonstrated to have thick, geomechanically competent seals.

- Modeling exercises are necessary to predict injectivity and plume movement, determine operational parameters, assess risk, and guide the development of an MVA plan. The Fort Nelson modeling exercises followed standard practices, protocols, and workflows that are commonly applied in the oil and gas industry. Those modeling approaches are also generally well accepted and understood by the regulatory community. The combination of industry and regulatory acceptance means those approaches are directly applicable to CCS in deep, carbonate saline formations. The results of the Fort Nelson modeling exercises offered robust and compelling technical support to the notion that the Fort Nelson site has the potential to be a world-class reservoir for CO_2 storage.

- MVA plans are required to ensure the injected CO_2 stays in the designated storage unit. This is essential to ensure the health and safety of the environment and local residents, maintain permit requirements, and quantify CO_2 storage for potential carbon credit monetization purposes. Challenges for MVA in the Fort Nelson area are primarily related to the remoteness of the candidate injection locations and the difficulty of the terrain with respect to both climate conditions and accessibility. Specifically, the boggy nature of the landscape means that there is a lack of access roads in the Fort Nelson area. The areas being considered as host sites for injection wells are, in fact, only accessible through the use of ice roads during the winter months. This lack of year-round infrastructure severely limits the movement of equipment needed to install, operate, and maintain MVA systems. However, it is important to note that these accessibility challenges are not insurmountable. Oil and gas exploration and production activities have been conducted in the area for decades. Over that time, industry has developed proven, cost-effective, and environmentally sustainable approaches to installing, operating, and maintaining a variety of production and injection projects that serve as excellent analogs for how to design and operate a CCS project.

- From a geologic perspective, the Fort Nelson area appears to have all of the elements of a CCS project that would put it in the world-class category. However, there are currently no regulatory or economic drivers in place that allow SET to make a sound business case for moving forward with a large-scale CCS project at Fort Nelson. Without a business case, the Fort Nelson project is not likely to be implemented.

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APPENDIX A

FORT NELSON DRAFT MONITORING, VERIFICATION, AND ACCOUNTING PLAN

FORT NELSON DRAFT MONITORING, VERIFICATION, AND ACCOUNTING PLAN

PROJECT OVERVIEW

The Plains CO_2 Reduction (PCOR) Partnership, led by the Energy & Environmental Research Center (EERC), is working with Spectra Energy Transmission (SET) to determine the effect of large-scale injection of carbon dioxide (CO_2) into a deep saline system for the purpose CO_2 storage.

SET's Fort Nelson plant is located in northeastern British Columbia, Canada, and is the largest sour gas-processing plant in North America (Figure A-1). A large expansion project is currently under way at the plant in response to the recent developments with shale gas plays in the Horn River Basin. Following this expansion, the Fort Nelson plant will become the largest single-point CO_2 emission source in British Columbia, emitting over 2 million metric tons of CO_2 a year and accounting for 2%–3% of the total CO_2 emissions of the province. It is worth noting that the emissions from the processing portion of the plant are approximately 95% CO_2 and 5% H_2S, with a small amount of methane. Because of the presence of H_2S, the emission stream is sometimes referred to as "sour" CO_2.

EERC JL41536.CDR

Figure A-1. SET's natural gas-processing plant in Fort Nelson, British Columbia, Canada.

With the growing tendency toward greenhouse gas regulations by both provincial and federal governments, SET is proactively exploring the addition of carbon capture and storage (CCS) technology to its Fort Nelson gas-processing plant (FNGP). The goal of CCS at FNGP would be to capture the stream of sour CO_2 that is separated by gas processing and store it in a deep saline formation. The application of CCS technology will permit SET to continue expansion of its gas-processing operations without a commensurate increase in CO_2 emissions. To that end, SET is working with the PCOR Partnership to develop the Fort Nelson CCS Feasibility project (Fort Nelson project), which would lead to the initiation of the first CCS project in British Columbia to inject over 1 million metric tons/year of CO_2 into a saline reservoir.

The PCOR Partnership has developed an approach that integrates site characterization; modeling and simulation; risk assessment; and monitoring, verification, and accounting (MVA) into an iterative process to produce meaningful results for large-scale CO_2 storage projects (Figure A-2). The proposed monitoring program will utilize a preinjection baseline data set and a staged injection-monitoring approach to allow for time-lapse data acquisitions collected during key intervals of project operation. The surface-, near-surface-, and deep subsurface-monitoring

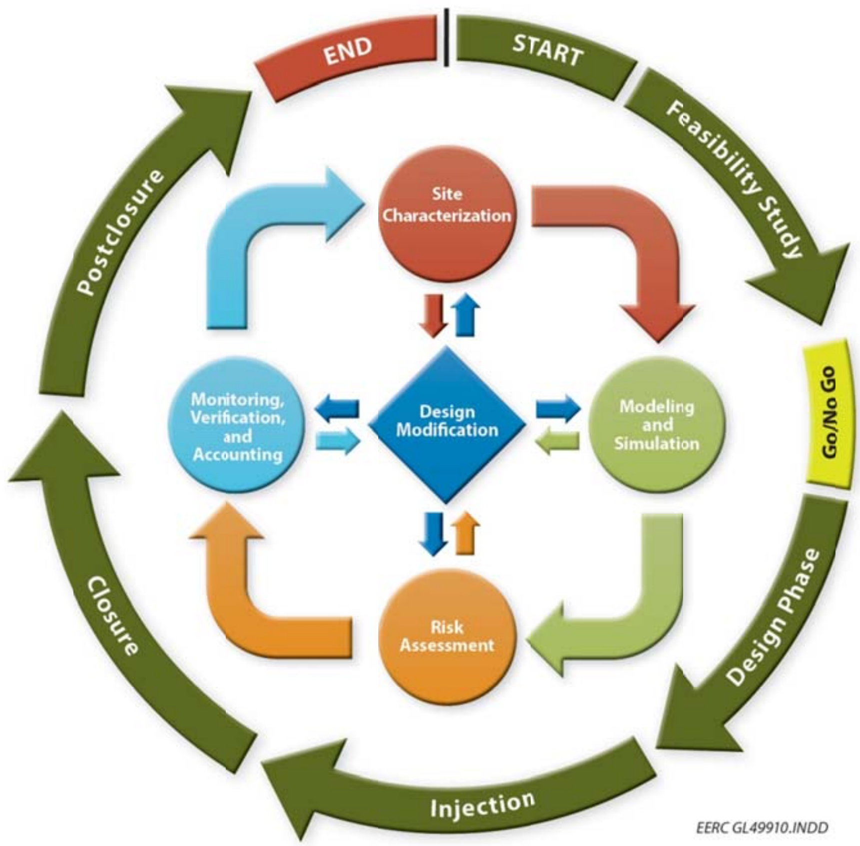

Figure A-2. Project elements of the Bell Creek project. Each of these elements feeds into another, iteratively improving results and efficiency of evaluation.

programs are engineered to have minimal impact on the commercial aspects of the project and address the challenges of limited site access, key risks identified to the project, and reservoir complexities experienced during an active large-scale CO_2 injection project. Monitoring data acquisitions are designed to enhance available data and evaluate the performance of the CO_2 storage projects.

The proposed MVA activities for this project can be broken down into two groups: 1) surface and shallow subsurface monitoring and 2) deep subsurface monitoring. This document outlines the methods by which the EERC proposes to monitor soil gas, surface water, and shallow groundwater to establish preinjection baseline conditions for the Fort Nelson project as well as acquisition of deep subsurface data sets to establish baseline conditions and track both CO_2 and fluid migration during the injection and postinjection process.

MVA OBJECTIVES

The overall objective of any MVA program is to provide a framework and methodology for monitoring the injection of CO_2 into the subsurface that provides regulators, the operator, and the general public adequate knowledge as to the disposition of the CO_2. Specifically, the Fort Nelson MVA program aims to meet four specific objectives: 1) assure the public that the project is safe and environmentally sound; 2) provide a rigorous, defendable accounting of CO_2 stored; 3) provide regulators with a metric of regulatory compliance; and 4) consider the guidelines established by the Canadian Standards Association (CSA) Report Z741-12 entitled "Geological Storage of Carbon Dioxide" (see Appendix B to overall report).

The Fort Nelson MVA program will provide environmental data on the project area prior to, during, and after CO_2 injection. This information will be used to verify that injected gas is remaining in place and is not impacting stratum above the cap rock. Should an out-of-zone fluid migration or leakage event occur, the MVA plan will aid in identifying the source of the event, evaluating the impact of the event, and allowing a response to the event in a timely manner.

Regulatory scrutiny will be a critical component of this and future MVA programs. The Fort Nelson MVA program will be structured to provide provincial regulators with the protocols, data, and documentation needed to meet the metric of project compliance. Additionally, the MVA program will seek to meet, and in certain cases, exceed the guidelines established by the CSA report.

It is the EERC's philosophy that MVA strategies be compatible with commercial operations and practices (i.e., integrate as much of the operational data as possible into the development of the MVA program) as well as be site-specific, operationally viable, sustainable, and cost-effective.

This document outlines the MVA activities that the EERC proposes be employed to 1) provide a baseline comparative data set between injection and preinjection conditions, 2) provide a means to account for and track subsurface CO_2 and water migration and interactions in the subsurface and their overall effect on the success of the project, and 3) address and monitor subsurface technical risk identified within the vicinity of injection operations at the project site. It should be noted that this is a preliminary plan. Once an injection location is confirmed, further characterization of the site will need to occur. This may result in modification of the proposed plan.

SURFACE AND SHALLOW SUBSURFACE MVA

Monitoring of surface and shallow subsurface environments is a critical part of any CCS project. The purpose of this monitoring is to establish baseline preinjection conditions that are naturally occurring in surface water, soil, and shallow groundwater aquifers in the vicinity of the CO_2 injection site and to provide a source of data to show that these environments remain unaffected by CO_2 injection or to quantify the impact of a leakage event.

A surface- and shallow subsurface-monitoring plan typically involves three parts, sampling of soil gas in the vadose zone, sampling of surface water, and sampling of shallow groundwater aquifers.

The Fort Nelson project area, however, is unique in its near-surface geology and hydrogeology. The area is a muskeg environment comprised of water-saturated soils and water table levels at or very near the ground surface. This type of environment affects the surface- and shallow subsurface-monitoring plan in two ways: 1) it may eliminate the ability to collect soil gas samples from the vadose zone (because the vadose zone does not exist) and 2) it may create almost limitless additional surface waters to sample in addition to the traditional surface waters (i.e., ponds, lakes, streams, and rivers).

Soil gas sampling consists of extracting representative samples of the gases present within the soil, which contains naturally occurring CO_2. Seasonal variations can dramatically impact the concentration of CO_2 in the vadose zone. Seasonal gas flux in near-surface soils is typically caused by plant roots and as part of the soil-weathering process. The ratio of the stable carbon isotopes that make up the CO_2 may also vary with the seasons; thus sampling and analysis will be repeated to capture these variations. If soil gas samples can be collected, the protocols for collection, handling, and analysis will follow ASTM International (ASTM) D 5314 – Standard Guide for Soil Gas Monitoring in the Vadose Zone.

Water sampling will be carried out to measure the levels of CO_2 and other dissolved constituents naturally present in surface and subsurface environments. Water well data obtained from the British Columbia Ministry of Environment’s B.C. Water Resources Atlas were compiled to select a subset of wells and surface water locations that will best establish preinjection baseline conditions. Shallow groundwater sampling is proposed to be carried out via a network of existing and planned groundwater wells. Samples collected from these wells will be analyzed for the composition of the dissolved constituents, including CO_2 content, and for the isotopic signature of the dissolved CO_2. Surface water samples will be collected from water bodies such as lakes and rivers near the CCS site and will undergo analysis similar to the groundwater samples.

Outlined below are the methods that will be implemented as part of the Fort Nelson MVA program. The MVA program will discuss monitoring associated with two possible injection locations. Beginning in the winter of 2011–2012, soil gas samples (where possible), surface water samples, and groundwater samples were to be collected semiannually until CO_2 injection was to begin. Once injection begins, soil gas, surface water, and groundwater will be sampled annually (during summer months to take advantage of optimal site access).

Monitoring Area

The area that will be monitored is defined in relation to the lease holdings of SET related to the Fort Nelson project. That is, SET will have a lease agreement for the pore space below a geographic area for the purpose of injecting CO_2, and this will be the same area in which the MVA activities will be performed. The area, shown in Figure A-3, is approximately 21,000 hectares in size.

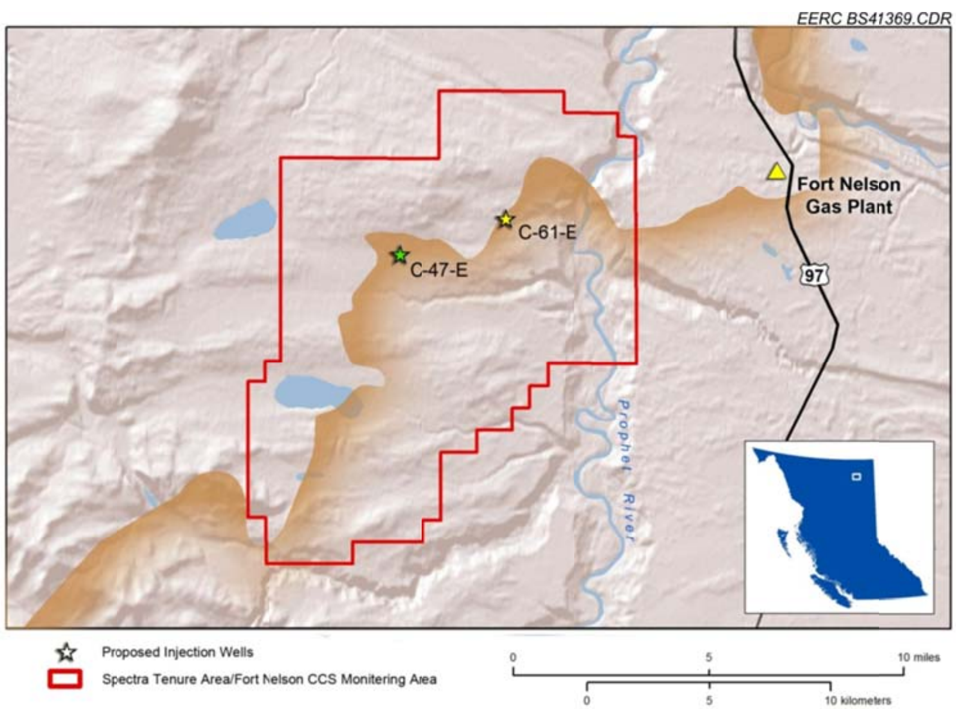

Figure A-3. Fort Nelson project-monitoring area.

Soil Gas Sampling

Sample Locations

Since the most likely pathway for CO_2 to "leak" to the surface is via existing and abandoned oil and gas wells drilled into the same formation as the injected CO_2, those well locations will be the targeted soil gas-sampling areas. Figure A-4 shows the location of the oil and gas wells within the monitoring area. During the first sampling event, a location on or near the well pad will be selected at each well site in the monitoring area, marked by GPS (global positioning system), and an attempt will be made to collect a soil gas sample. Locations where soil gas samples cannot be collected will be noted as such, and soil gas sample collection will not be attempted at that site during future sampling events. Locations where soil gas samples are successfully collected will continue to be collected during future sampling events.

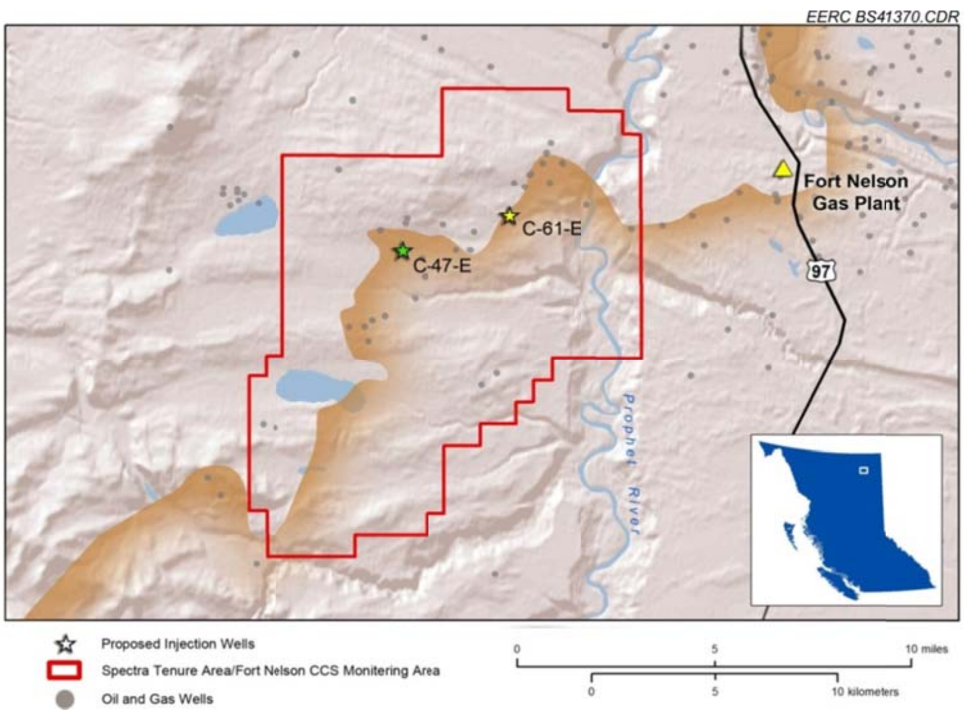

Figure A-4. Fort Nelson CCS Project proposed soil gas sampling locations. Soil gas sampling would be conducted at existing oil and gas well locations within the Spectra Tenure Area

Sample Analyses

Soil gas samples will be submitted to an approved laboratory and analyzed for the following analytes:

- CO_2
- C1

- Carbonyl sulfide (COS)
- Ethane (C_2H_6)
- Hydrogen sulfide (H_2S)
- Nitrogen (N_2)

In addition, the following parameters will be measured in the field for each sample collected:

- CO_2
- Oxygen (O_2)

Sample Collection and Handling

Soil gas sample collection procedures will follow guidance outlined in ASTM D 5314. All sample locations will be identified and marked by GPS. A stainless steel rod with a retractable tip will be driven into the ground (either with a slide hammer or electric rotary hammer) to a depth of approximately 1 m. The rod is then retracted to expose an integrated mesh screen; silicon tubing is attached to the end of the rod, and a small hand pump is used to purge the rod before the sample is collected. A minimum of two probe casing volumes will be removed prior to sampling.

Soil gas will be pumped into a 1-liter Tedlar® bag for field screening of CO_2 and O_2, using a handheld gas analyzer. Soil gas samples for laboratory analysis will be collected using 3-liter foil gas bags filled to a maximum of 75% capacity, labeled appropriately, and handled as described in standard methods. After sample collection, the rods should be removed, cleaned, and readied for subsequent use.

Surface Water Sampling

Sample Locations

Certain water features exist in the Fort Nelson project monitoring area or in close proximity to it and are easily identifiable as targets for surface water sampling. Specifically, Milo Lake, Klowee Lake, and the Prophet River will be sampled.

In addition to these three surface waters, during the initial sampling event, personnel will identify other specific water bodies to sample and mark them with GPS for future sampling. These sampling locations will likely be bogs or swamps containing sufficient water and located within the monitoring area.

Sample Analyses

Surface water samples will be submitted to an approved laboratory and analyzed for the following analytes:

- Carbon-13 isotopes (^{13}C)

- CO_2
- Carbon
  - Total inorganic
  - Total organic
  - Dissolved inorganic
  - Dissolved organic
- Helium-3 (^3He)
- Hydrocarbons
- H_2S
- Metals
  - Total (unfiltered)
  - Dissolved (filtered and unfiltered)
- Oxygen-18 isotopes (^{18}O)
- Strontium-86 isotopes (^{86}Sr)
- Strontium-87 isotopes (^{87}Sr)
- Tritium (T) also known as hydrogen-3 (^3H)

In addition, the following parameters will be measured in the field for each sample collected:

- Temperature
- pH
- Specific conductance (or electrical conductivity)
- Dissolved oxygen
- Total dissolved solids
- Oxygen reduction potential

Sample Collection and Handling

Surface water samples will be collected and handled in accordance with protocols and methods specified in the 2003 edition of the British Columbia Field Sampling Manual: For Continuous Monitoring and the Collection of Air, Air-Emission, Water, Wastewater, Soil, Sediment, and Biological Samples, Part E "Water and Wastewater Sampling," Subsection "Ambient Freshwater and Effluent Sampling."

In summary, samples from surface waters will be collected and handled in the following manner:

- Sample bottles of the appropriate size and material should be provided by an approved laboratory, with the necessary preservative (if required) for the specified analyte.

- Surface water samples will be collected as "grab" samples. Samples should be collected with as little suspended solids and debris as possible. Samples should be collected as far into the water body as possible without jeopardizing the sampler's safety. Points of entry into water bodies will be marked with GPS for future sampling.

- Specific sampling protocols are detailed in Section 4.1 (Lake) and Section 4.2 (River/Stream) in the British Columbia Field Sampling Manual. Samples collected from surface water such as bogs, swamps, or pools should use the protocol described in Section 4.1.

- Once samples have been collected, they should be placed in a cooler and kept cool (near 5°C) until arrival at the laboratory for analysis. Attention should also be given to chain-of-custody procedures and holding time requirements.

For more detailed information regarding the collection and handling of groundwater samples, personnel should consult the British Columbia Field Sampling Manual.

Groundwater Sampling

Sample Locations

Within the monitoring area, very few groundwater wells exist. Currently there are five groundwater wells in the monitoring area, which are owned by SET.

It is anticipated that additional groundwater wells will be installed in conjunction with the alternative injection well. Groundwater samples will be collected from the existing four wells previously sampled and the wells installed with the alternative injection well. Figure A-5 shows the location of the existing groundwater wells to be sampled.

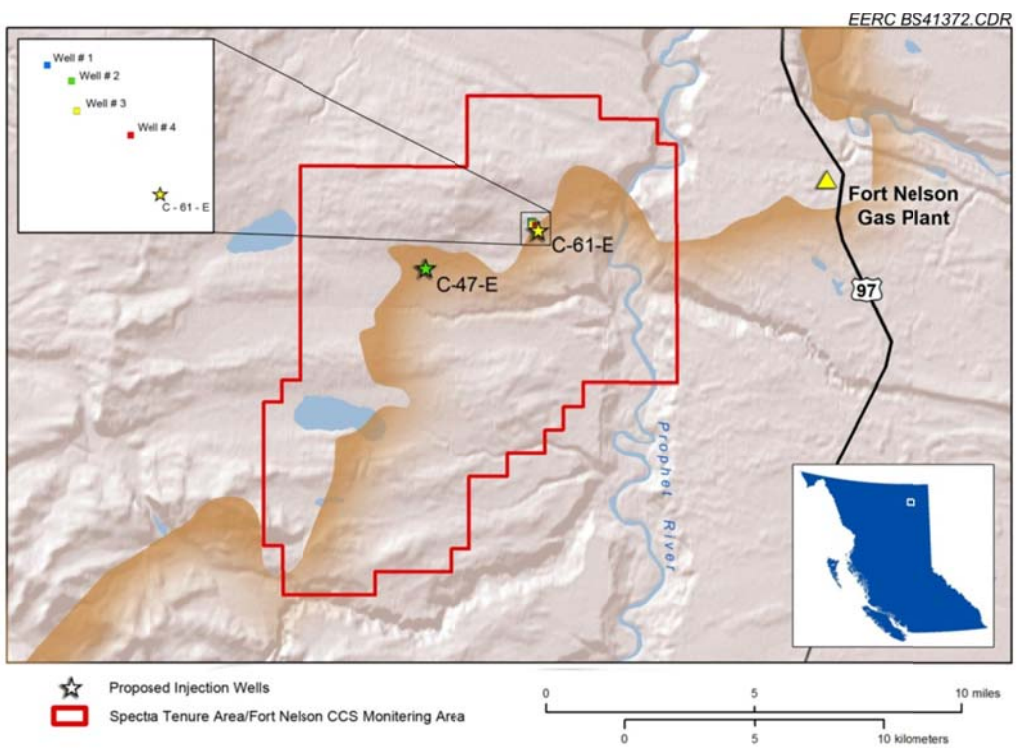

Figure A-5. Groundwater-sampling locations.

Sample Analyses

Groundwater samples will be submitted to an approved laboratory and analyzed for the following analytes:

- Carbon-13 isotopes (^{13}C)
- CO_2
- Carbon
  - Total inorganic
  - Total organic
  - Dissolved inorganic
  - Dissolved organic
- Helium-3 (^{3}He)
- Hydrocarbons
- H_2S
- Metals
  - Total (unfiltered)
  - Dissolved (filtered and unfiltered)
- Oxygen-18 isotopes (^{18}O)
- Strontium-86 isotopes (^{86}Sr)
- Strontium-87 isotopes (^{87}Sr)
- Tritium (T) also known as hydrogen-3 (^{3}H)

In addition, the following parameters will be measured in the field for each sample collected:

- Temperature
- pH
- Specific conductance (or electrical conductivity)
- Dissolved oxygen
- Total dissolved solids
- Oxygen reduction potential

Sample Collection and Handling

Groundwater samples will be collected and handled in accordance with protocols and methodologies specified in the 2003 edition of the British Columbia Field Sampling Manual under the "Groundwater Pollution Monitoring" subsection.

In summary, groundwater samples will be collected and handled in the following manner:

- Sample bottles of the appropriate size and material should be provided by an approved laboratory, with the necessary preservative (if required) for the specified analyte.

- Groundwater wells should be purged prior to sampling. Purging should be performed using either existing pumps already in place (in the case of a drinking water well) or a submersible pump temporarily put in place specifically for groundwater sampling. If the use of a submersible pump is not possible, the well should be purged using a disposable bailer. Purging should continue until measured readings for pH, temperature, and conductivity are stable. If this equilibrium volume is not possible, the sampler should remove a minimum of four well volumes.

- Groundwater samples should be collected using either existing pumps or temporarily placed pumps. If pumping is not possible, the sampler should use a disposable bailer to collect the sample.

- Once samples have been collected they should be placed in a cooler and kept cool (near 5°C) until arrival at the laboratory for analysis. Attention should also be given to chain-of-custody procedures and holding time requirements.

For more detailed information regarding the collection and handling of groundwater samples, personnel should consult the British Columbia Field Sampling Manual.

Field Quality Assurance/Quality Control (QA/QC) Program

To assure the accuracy of the sample program, certain field protocols will be utilized. This will include the use of disposable nitrile gloves (newly donned for each sample preparation) as well as thorough decontamination of reused sampling equipment prior to and between sample collection events. Decontamination procedures include washing and rinsing sample probes and field multiparameter meters using Alconox and deionized water. All field instruments will also be calibrated daily to ensure that they are operating properly and produce data that satisfy the objectives of the sampling program.

In addition, field sampling events will include the use of field blanks (i.e., duplicate samples). Duplicate samples consist of two or more samples collected at the same time and location. These samples are then submitted to the same laboratory as separate samples for the purpose of assessing the combined accuracy of the field sampling and laboratory analysis.

Field control samples will be submitted to the laboratory without special coding that would identify the sample as a QA/QC sample, therefore providing a "blind" control. Field control samples will be preserved in the same manner as those of the sample batch.

DEEP SUBSURFACE MVA PROGRAM

The EERC has developed a deep subsurface MVA program for the Fort Nelson project, to address technical subsurface risks and monitor CO_2 and fluid migration both in the storage complex and in the subsurface as a whole. The goal of the deep subsurface MVA program is to effectively monitor and track the movement of injected CO_2 and reservoir fluids in the deep subsurface in order to demonstrate safe and effective storage, identify fluid migration pathways, and determine the fate of injected CO_2. Both baseline and time-lapse data acquisitions are necessary to optimize the utility of the MVA program. The majority of baseline data acquisitions focus on minimizing the variance between preinjection and injection conditions resulting from pressure and fluid changes in the reservoir.

The deep subsurface MVA program will utilize a combination of wellbore technologies, such as pulsed-neutron log (PNL) tools, downhole pressure and temperature monitoring, and 3-D vertical seismic profile (VSP) acquisition, to measure reservoir changes during injection, track the vertical and lateral extent of fluid and CO_2 movements during the injection process, and account for injected CO_2 over the storage site lifetime. The data acquired from these wellbore technologies will then be evaluated and integrated into refined geomodeling activities (reservoir modeling, 3-D MEM [mechanical earth model], and the full-field geologic model). Some data can be directly inputted into geomodeling software, while other data types, such as historic reservoir pressure data, must be matched within models through reservoir simulation during the history-matching process. All of these inputs serve to constrain modeling and simulation predictions and guide future MVA activities.

Data acquired will also help to bind simulation predictions in the context of real-world data. Key parameters will be used to update modeling and simulation work on an iterative basis in order to identify and eliminate variances between the real-world physics of injection and predicted behavior of the CO_2, storage complex fluids, and rock matrix. This iterative process allows for decreased uncertainty in predictions. Additionally, monitoring data will provide insight into mechanisms that could contribute to the understanding of ultimate CO_2 storage capacity, an accurate assessment of long-term retention, and the ability to predict CO_2 movement and chemical interactions within the reservoir after site closure.

Dual-Track MVA

Previous planning for the Fort Nelson project was based on a planned injection location at Well c-61-E. However, dynamic simulations of some injection scenarios indicated that the injected sour CO_2 could contact the neighboring Clark Lake Slave Point A and B gas pools in approximately 30 years, which is before the end of the expected productive life of the fields. This was identified as a potential risk, and additional data collection and a reevaluation of the potential injection scenarios resulted in the movement of the injection site to an area farther to the west, near c-47-E.

A geologic structure called a graben separates the two potential injection locations. A graben is a structure formed by the down-dropped block between two normal faults. There has been a paucity of data available regarding several key properties of the graben, and the transmissivity values used in simulation runs were such that the graben’s presence did not significantly influence either risk track. It is anticipated that this will change as new data become available and additional history matching and simulations are conducted.

Although the new injection location reduced risks such as contacting the Clark Lake Slave Point A and B gas pools during their productive life, other potential risks such as injectivity and storage capacity also changed because detailed information about the new target reservoir and geology near c-47-E are not currently well-defined. Therefore, for current work, two scenarios were developed to assess the relative merits of injecting sour CO_2 in and around either c-47-E or c-61- E:

- **Scenario 1** is defined as injecting at Location c-47-E to the west side of the graben.
- **Scenario 2** is defined as injecting at the original location, c-61-E, to the east side of the graben.

While the two injection scenarios vary in location and potential risks, the technologies used to monitor the two scenarios will be the same. The difference between the scenarios is shown when determining the location of monitoring wells and establishing the frequency in which the various technologies will be deployed. Therefore, the remainder of this section provides a brief description of the location of each injection scenario and the placement of monitoring wells. Also provided is an overview of the proposed monitoring technologies.

Description of Injection Scenario 1

In Scenario 1, the graben acts as a natural barrier, and dynamic simulation predicts that it will isolate Clark Lake Slave Point Gas Pool B from the CO_2 plume beyond the time horizon of the model. Based on the predicted extent of the plume, the positioning of monitoring wells was selected and is shown in Figure A-6. These wells are intended to monitor the growth of the plume west of the graben and also to verify the lack of increased CO_2 concentration east of the graben. Table A-1 depicts the suite of technologies to be used for monitoring in Scenario 1.

Description of Injection Scenario 2

Due to the increased proximity to the Clark Lake gas pools in Scenario 2 as well as to the increased degree of pressure communication between the storage complex and the gas pools, there are some slight variations in the monitoring strategies employed (Figure A-7). For instance the lack of easterly containment of the CO_2 plume necessitates a monitoring plan that measures plume growth in the direction of the Clark Lake Slave Point Gas Pool A, in such a way as to iteratively update models and maintain accurate estimates of the time frame when CO_2 is likely to reach the gas pool. Table A-2 depicts the suite of technologies to be used for monitoring in Scenario 2.

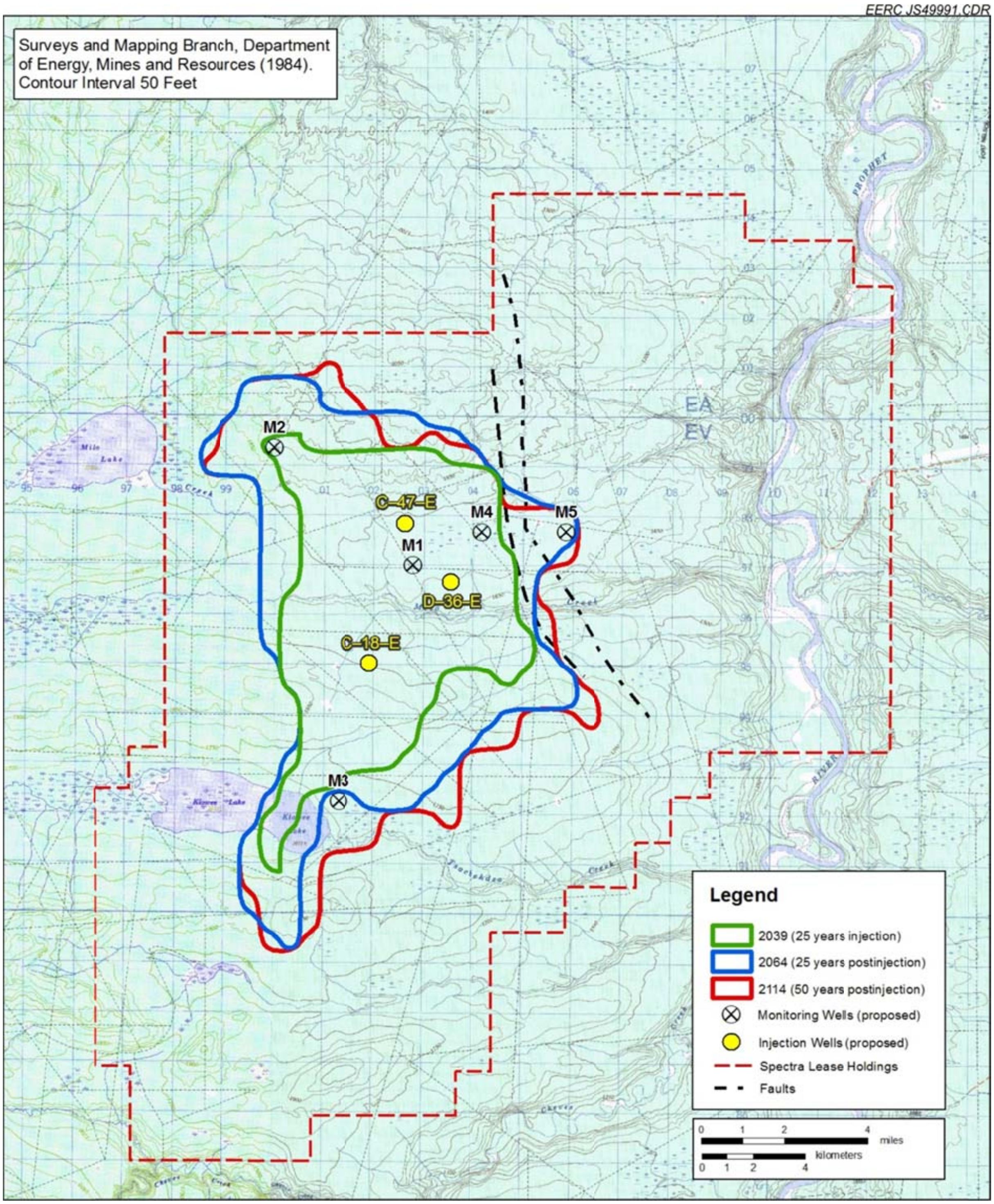

Figure A-6. Scenario 1 site map showing CO_2 plume extent indicated by simulation and planned locations of injection and monitoring wells.

Table A-1. Deep Subsurface-Monitoring Overview for Fort Nelson Injection Scenario 1

Monitoring Technique	Number of Locations	Frequency (baseline)	Frequency (operational)	Measurement
PNL	Eight wells or more (including c-47-E)	Once	TBD[1]	Water, oil, and CO_2 saturations near wellbore
Wellhead Pressure, Temperature, and Flow	All active injection and monitoring wells and any existing wells not compliant with CSA Z741-12 Clause 7.3.7	Near-continuous	Near-continuous	Wellhead pressure, temperature, and flow in injectors
Downhole Pressure and Temperature,	All active injection and monitoring wells	5-minute intervals	5-minute intervals	Downhole pressure and temperature
3-D Surface Seismic	~100 square miles	Once	TBD	3-D surface seismic survey
3-D VSP	Central monitoring well	Once	TBD	Downhole seismic acquisition at the listed wells
Ultrasonic Scanner	Three injector wells, C-47-E, C-18-E, and D-36-E	Once	TBD	Ultrasonic image logs
In Situ Sampling	Monitoring Well M5	Once	TBD	Various parameters obtained by fluid analysis

[1] To be determined.

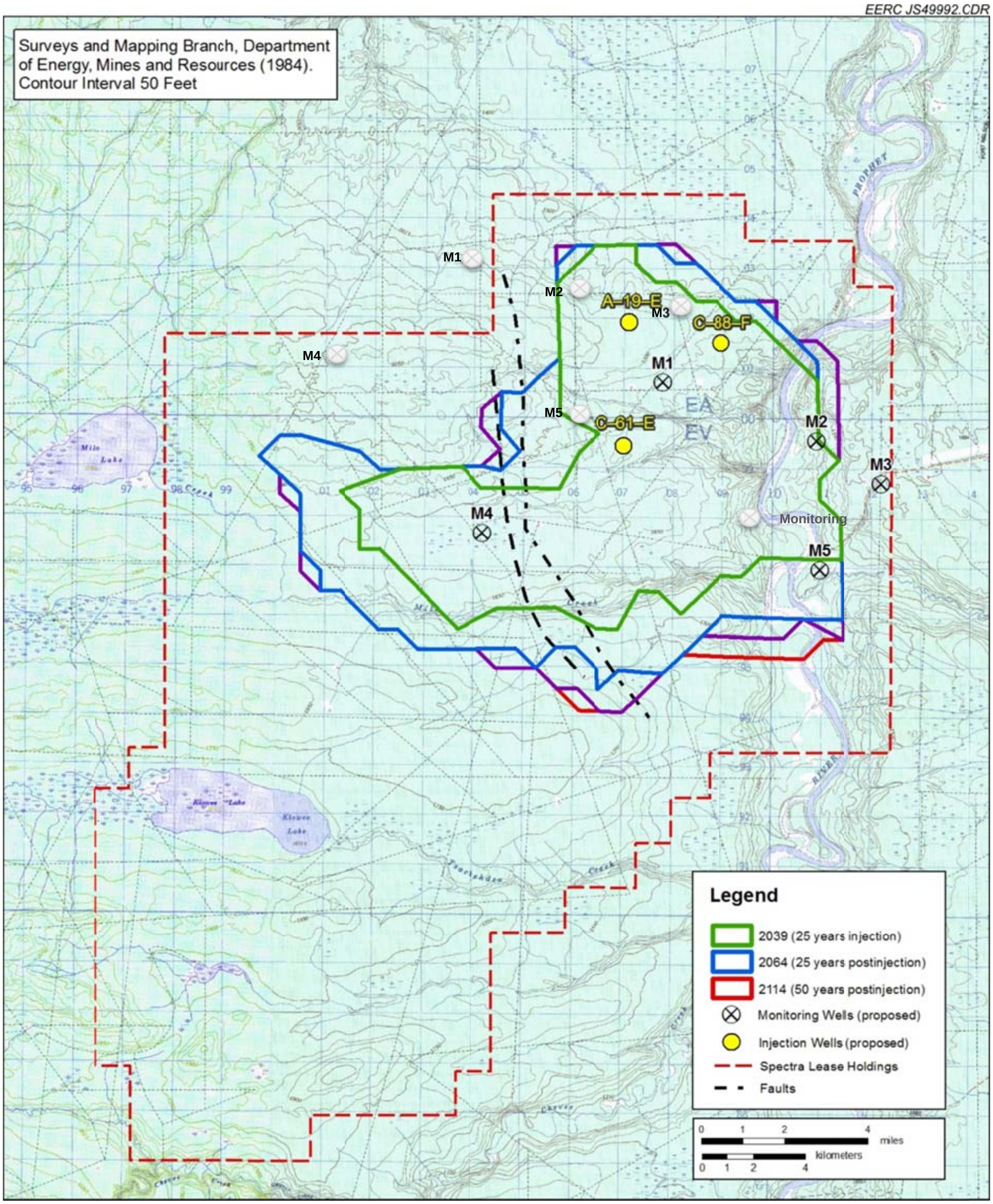

Figure A-7. Scenario 2 Site map, showing CO_2 plume extent indicated by simulation, and planned locations of injection and monitoring wells.

Table A-2. Deep Subsurface-Monitoring Overview for Fort Nelson Injection Scenario 2

Monitoring Technique	Number of Locations	Frequency (baseline)	Frequency (operational)	Measurement
PNL	Eight wells or more (including c-61-E)	Once	TBD	Water, oil, and CO_2 saturations near wellbore
Wellhead Pressure, Temperature, and Flow	All active injection and monitoring wells and any existing wells not compliant with CSA Z741-12 Clause 7.3.7	Near-continuous	Near-continuous	Wellhead pressure, temperature, (and flow in injectors)
Downhole Pressure and Temperature,	All active injection and monitoring wells	5-minute intervals	5-minute intervals	Downhole pressure and temperature
3-D VSP	Central monitoring well	Once	TBD	Downhole seismic acquisition at the listed wells
3-D Surface Seismic	~140 square miles	Once	TBD	3-D surface seismic survey
Ultrasonic Scanner	Three injector wells, C-61-E, A-19-E, and C-88-F	Once	Once	Ultrasonic image logs
In Situ Sampling	Monitoring Well M2	Once	TBD	Various parameters obtained by fluid analysis

Description of Proposed Monitoring Technologies

Pulsed-Neutron Logs

Baseline PNLs will be collected from total well depth (approximately 610 m) to the surface casing shoe from each of the planned injection and monitoring wells in addition to any existing wells that penetrate the storage complex. This will assure coverage of the Keg River, Sulphur Point, and Slave Point Formations along with any shallower formations that later prove to be affected by injection. Two time-lapse repeat logging runs are anticipated, one of which will occur shortly after temperature and pressure indicate arrival of CO_2 at the central monitoring well. The other will be determined based on predictive simulation results to determine the area of the CO_2 plume and/or to determine timing of time-lapse seismic surveys.

PNLs are acquired via wireline conveyance in conjunction with a crane truck. Tool specifications allow for acquisition through 2 ⅞-inch tubing and are run with wellhead pressure control equipment (wireline blowout preventer [BOP], lubricator, and grease injection). Logging operations require each injection well to be sequentially taken off-line, taking approximately 8 hours per well from rig up to rig down. Scheduling and acquisition will be coordinated between SET and the logging service provider to allow for minimal impact to injection activities. Access to the Fort Nelson site is provided by an ice road, so temperature and weather will be key factors in determining the scheduling of logging runs and other manual monitoring activities. It will be critical to schedule these activities thoughtfully and well in advance in order to acquire data in a timely fashion.

PNLs provide a quantitative assessment of water, oil, and CO_2 saturations in the near-wellbore environment. Applications include the following:

- Monitoring changes in water, natural gas, and CO_2 contacts over time.

- Ability to:
  - Determine CO_2 storage efficiencies.
  - Identify channeling between lithofacies and/or causes of CO_2 breakthrough.
  - Aid in determination of effective storage volume.

- Ability to identify vertical CO_2 migration along the wellbore into overlying formations and/or locate accumulations of CO_2 into overlying formations, which have migrated vertically above the top of the cement (if present).

- Provide an indication of cement integrity and/or identify wells that are candidates for remediation activities (if present).

- Provide a means to correlate seismic data with quantitative CO_2 saturation and the vertical distribution of CO_2 within the reservoir.

- Provide a near-wellbore saturation history for predictive simulation history match.

- Provide a means to identify horizontal fluid migration.
- Provide an indication of flow boundaries in the interwell environment.
- Identify lithofacies that are not accepting injection.
- Identify vertical flow boundaries in the near-wellbore environment.

Given these applications PNLs facilitate compliance with guidelines calling for monitoring of potential leakage, wellbore integrity, and the extent of both the CO_2 plume and water displacement zone. In addition, they are useful for initial indication of geochemical changes and can signal the necessity of downhole sampling.

Wellhead Pressure, Temperature, Flow Rates, and Well Testing

Real-time wellhead pressure, temperature, flow, and well test data will be collected periodically for all active injection and monitoring wells. Measurements will be collected as a baseline during the preinjection period and will continue into the injection period of the project at the same frequency.

Wellhead pressure, temperature and flow data can be collected inexpensively and reliably. This information can be used to calibrate and interpret other pressure and temperature data, and may indicate when wellhead samples should be collected for testing. Applications include the following:

- Ability to identify injectivity or well integrity issues.
- Ability to correlate injection pressure with downhole and reservoir pressures.
- A valuable high-density input for injection pressures and volumes for predictive simulation history matching.
- Ability to predict the physical properties and phase behavior of injected CO_2.
- Ability to quantify injected volumes of CO_2, oil, and water.
- Ability to provide an indication of CO_2 arrival at monitoring wells.
- Ability to monitor for pressure communication within and between the structures of the storage complex.

Wellhead measurements secure compliance with guidelines including those that call for monitoring of injected volumes of CO_2, gas flow rate, and surface injection pressure and temperature.

Downhole Pressure and Temperature Gauges

Permanent casing-conveyed downhole pressure and temperature gauges will be deployed in each of the five monitoring wells for permanent downhole monitoring (PDM). Injection wells C-47-E, C-18-E, and D-36-E will use hanging sensors for PDM. These downhole pressure and temperature gauges will provide real-time pressure and temperature data at a minimum frequency of 5 minutes. They will be placed at intervals that vary from well to well, with the objective of acquiring temperature and pressure data at critical points within designated formations.

Downhole gauges and casing-conveyed gauges have been selected to avoid interference with injection or other monitoring activities. Applications for PDM include the following:

- In situ pressure and temperature data:
  - A means to correlate wellhead injection and monitoring pressures to reservoir pressure.
  - A valuable input of interwell reservoir pressure for predictive simulation history matching.
- Potential to provide an indication of CO_2 arrival at the central monitoring well.
- Potential to provide an indication of CO_2 channeling along a vertical cross section within the reservoir.
- Provide an indication of out-of-zone fluid migration along the monitoring wellbores or CO_2 losses into the next overlying zone of permeability above the primary seal.
- Provide an input for geomechanical assessments.
- Ability to measure the pressure/temperature regime of the reservoir.
- Assess zonal pressure isolation between various lithofacies of the Keg River Formation as well between the Keg River and Sulphur and Slave Point Formations.

These applications facilitate compliance with guidelines recommending the monitoring of pressure both within the storage complex and in the deepest overlying permeable formation.

Vertical Seismic Profiling

Baseline and repeat VSPs will be conducted with a downhole geophone array deployed into the central monitoring well. A baseline survey will be collected, with at least one time-lapse repeat being conducted during injection. The VSP equipment will consist of a 50-level retrievable geophone. The VSP data will allow for calibration and enhanced processing of the time-lapse 3-D surface seismic data, characterization of subsurface structure, and time-lapse images of changes in CO_2 saturation. The timing and quantity of repeat surveys are still under consideration and will be guided by reservoir response to CO_2 injection and coincide with time-lapse surface seismic and PNL activities.

Offset VSP surveys as illustrated in Figure A-8 utilize an array of sensors in a wellbore to record seismic signals originating from one to four seismic sources located on the surface which are offset a distance (typically between 15 and 610 m) from the wellhead. Typically, the first measurement is taken at the deepest point within the wellbore required for the survey, after which the sensors within the wellbore are incrementally relocated to a shallower depth, with the processes being repeated as many times as necessary.

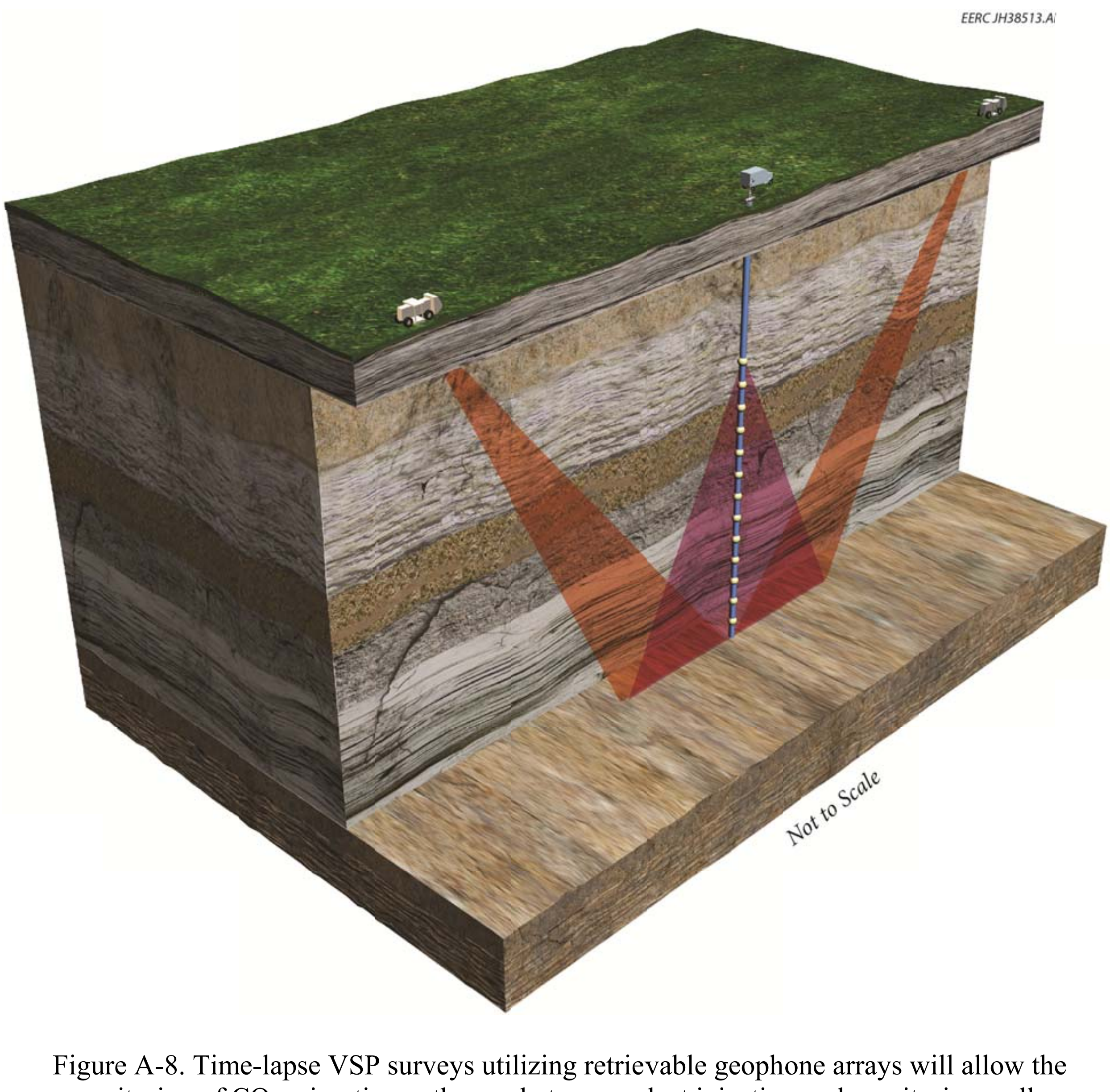

Figure A-8. Time-lapse VSP surveys utilizing retrievable geophone arrays will allow the monitoring of CO_2 migration pathways between select injection and monitoring wells.

Applications include the following:

- Identify horizontal channeling of CO_2 between an injection and monitoring wells.
- Qualify or update estimates of effective storage capacity.
- Monitor the shape of the areal CO_2 plume.
- Ability to extrapolate PNL data into an interwellbore environment.
- Provide a means of correlating surface seismic data to higher-resolution VSP data and higher-resolution VSP data to vertical CO_2 distribution via PNLs.
- Provide an input for interwell reservoir saturation for predictive simulation history matching.
- Identify the distribution of heterogeneities and lateral flow boundaries.

VSPs meet provisions of guidelines by monitoring the spatial distribution of the CO_2 plume, the elevated pressure region, and the zone of formation water displacement. They can be used to identify potential out-of-zone migration and confirm the integrity of the confining lithofacies.

3-D Surface Seismic Survey

A 259-km^2 3-D seismic survey will be collected over the area of the predicted 25-year CO_2 plume. Timing and quantity of repeat surveys are still under consideration. Repeat surveys may consist of smaller areas of interest within the larger baseline seismic extent. Time-lapse 3-D surface seismic survey data provide a qualitative estimate of areal CO_2 saturation changes in the interwellbore environment as well as updip and downdip of the field.

A 3-D surface seismic survey, as shown in Figure A-9, utilizes an array or grid of sensors or geophones deployed on the surface, which can cover multiple square kilometers, to record seismic signals generated by single or multiple surface seismic sources. 3-D seismic can detect features that underlie the grid, thereby allowing volumetric interpretations of the subsurface. 3-D seismic surveys are especially useful for supplementing detailed characterization work over an area of multiple square kilometers in size or when geologic structure can vary within the study area.

Applications include the following:

- Identify horizontal channeling of CO_2 between multiple injection and monitoring wells.
- Monitor the shape of the areal CO_2 plume, streamlines, and lateral migration pathways.
- Extrapolate PNL into interwellbore environment.

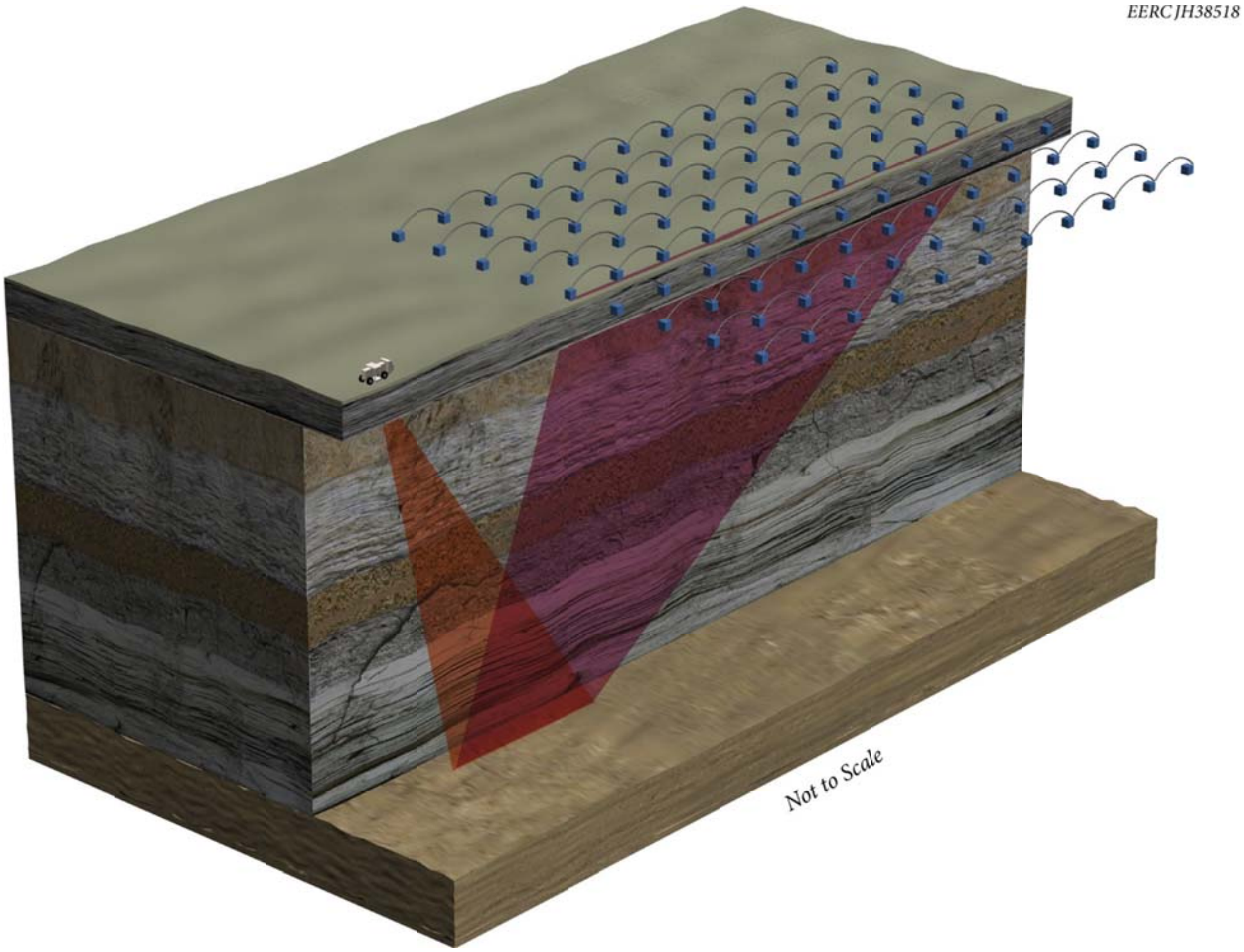

Figure A-9. A 3-D surface seismic survey uses an array of geophones deployed on the surface to record seismic signals generated by single or multiple surface sources and rebounding from features at depth. 4-D surface seismic, primarily used for monitoring, is essentially a time-lapse 3-D surface seismic survey given special consideration to ensure repeatability.

- Provide a means of correlating surface seismic data to higher-resolution VSP surveys and to vertical CO_2 distribution via PNLs.
- Provide an input of interwell reservoir saturation changes for predictive simulation history matching.
- Identify the distribution of lateral heterogeneities and flow boundaries in the interwellbore environment.
- Improve the accuracy of the geologic model as a direct structural geology input.
- Corroborate other model inputs from other geological characterization activities as well as improve data integration between varying data sources.

- Provide a verification method for reservoir simulation activities, including history matching and CO_2 injection simulations.

Surface seismic profiles provide compliance with guidelines by monitoring the elevated pressure region, the spatial distribution of the CO_2 plume, and the zone of formation water displacement. Additionally, they can be used to identify potential out-of-zone migration and confirm the integrity of confining formations.

Ultrasonic Scanner

Ultrasonic imaging is planned in the three injector wells, c-47-E, c-18-E, and d-36-E, following casing activities. A single suite of repeat logs is planned and is likely to coincide with repeat PNL logs for logistical reasons. However, repeat ultrasonic logs may be taken earlier if CO_2 breakthrough to the central monitoring well takes longer than expected.

Ultrasonic imaging accomplishes compliance with British Columbia's acid gas disposal guidelines by allowing the detection of imperfections and corrosion of casing materials. Applications include the following:

- Perform 360° analysis of the cement bond.

- Determine annulus cement strength.

- Determine the presence of a microannulus.

- Confirm hydraulic isolation.

- Map annulus material as solid, liquid, or gas, and determine the acoustic velocity of the annulus material.

- Determine borehole fluid properties.

- Locate and image channels or defects in annular isolation material.

- Visualize the position of casing within the borehole.

- Perform casing thickness analysis for collapse and burst pressure analysis.

- Determine casing internal and external diameters for monitoring purposes and to locate and quantify casing wear damage or metal loss caused by milling, drilling, fishing operations, internal or external scale buildup, casing corrosion, and casing damage or deformation.

- Locate and identify casing holes and perforated intervals.

- Identify casing profiles and weight changes.

The applications of ultrasonic imaging further accomplish compliance with guidelines by confirming the integrity of the wellbore and portions of the confining zone (particularly in wellbore environment).

In Situ Testing and Sampling

Downhole fluid samples will be collected from monitoring wells at the time of their completion, with repeat samplings scheduled as needed. The locations of the monitoring wells for the selected injection scenario will be chosen specifically with the intent of mitigating risks associated with the specific injection scenario.

When and if downhole temperature and pressure data indicate the incidence of the CO_2 plume at a monitoring well, repeat fluid samplings may be scheduled. These samplings will serve to monitor further expansion of the CO_2 plume and any geochemical reactions taking place in the reservoir. In the interest of cost and reliability, wireline-based sampling methods will be used rather than installed sampling tools. Wireline-based methods are also preferable because of the high logistical cost of sight access, which reduces the total number of samples likely to be collected by either method.

Further applications include:

- Fluid samples collected and maintained at in situ reservoir conditions (pressure, volume, temperature [PVT]) until geochemical and laboratory analysis can be conducted.
- Fluid samples collected for tracer analysis applications in order to track fluid movement within the subsurface.
- Hydrocarbon typing.
- Fluid compositional grading within a hydrocarbon column.
- In situ phase separation tests and real-time estimations of fluid or gas compressibility.
- Fluid density and viscosity.
- pH analysis at reservoir conditions.

In situ testing affords the Fort Nelson project further compliance with CSA guidelines by allowing the confirmation and quantification of geochemical changes in the reservoir. In addition, in situ testing can facilitate direct confirmation of the arrival of the CO_2 plume or formation water displacement front at the tested well.

SUMMARY

The combined surface, near-surface, and deep subsurface MVA program outlined in this document is designed to address technical subsurface risks to the Fort Nelson project. A robust monitoring program requires the use of multiple synergistic technologies to identify, confirm, locate, and quantify the behavior and interaction of fluids and rock in the subsurface. Insight gained from an effective MVA program integrates into modeling and simulation activities, providing higher confidence in predictions and allowing for increased understanding of technical project risks.

APPENDIX B

CSA REQUIRED SPECIFICATIONS FOR SITE SELECTION, SITE CHARACTERIZATION AND ASSESSMENT, MODELING FOR CHARACTERIZATION, AND MONITORING AND VERIFICATION

CSA REQUIRED SPECIFICATIONS FOR SITE SELECTION, SITE CHARACTERIZATION AND ASSESSMENT, MODELING FOR CHARACTERIZATION, AND MONITORING AND VERIFICATION

CSA STANDARD FOR GEOLOGICAL STORAGE OF CARBON DIOXIDE

In October 2012 the Canadian Standards Association (CSA) released a standard for geological storage of CO_2 entitled "Standard Z741-12 Geological Storage of Carbon Dioxide." The standard was developed by the CSA Technical Committee on Geological Storage of Carbon Dioxide, which was a joint Canada–U.S. Technical Committee. This committee included 38 individuals with a broad range of experience in government, academia, and the oil and gas industry.

The CSA standard can be considered to be comprehensive in that it provides detailed descriptions of practices and procedures for essentially all aspects of a CCS project. Specifically, the CSA standard provides guidance for what it considers to be the six key elements of a CCS project. Those elements include 1) management systems; 2) site screening, selection, and characterization; 3) risk management; 4) well infrastructure development; 5) monitoring and verification; and 6) closure.

This standard, by itself, does not have the force of law unless it is officially adopted by a regulatory authority (Canadian Standards Association, 2012). However, it is possible that the CSA standard, in total or in part, could be adopted or referred to by regulatory authorities. With this in mind, the Fort Nelson Carbon Capture and Storage Feasibility project (Fort Nelson project) was compared to the CSA standard.

The Energy & Environmental Research Center (EERC) evaluation compared preinjection work completed by the EERC and Spectra Energy Transmission (SET) for the Fort Nelson project to select required specifications presented in Sections 5.3, 5.4, 5.5, 8.3, and 8.4 of the CSA standard. The text below is taken verbatim from the aforementioned sections of the CSA standard. Each required specification has been highlighted according to a color code that indicates where the Fort Nelson project clearly complies with the draft standard, where it clearly does not comply, where it may comply after clarification or moderate expansion, and where it is out of the scope of the preinjection program.

- Clearly complies
- May comply after clarification or moderate expansion
- Clearly does not comply
- Outside the scope of preinjection program

It should be noted that planning carried out by the EERC and referred to as monitoring, verification, and accounting (MVA) is equivalent to work described in the CSA standard and referred to as monitoring and verification (M&V).

EVALUATION OF FORT NELSON CCS COMPLIANCE

5.3 Site selection

Site selection builds on the geological evaluation and land use considerations, building on the activities within Clause 5.2 during the initial site screening process. During the selection, the following should be assessed for sites that passed the screening stage:

(a) subsurface criteria:

(i) capacity — refinement of site storage capacity;

(ii) injectivity — influences the number of wells, well design and injection pressure.

(iii) storage security, including the potential for leakage through

(1) weak seals along faults and fractures, assessment of which may include

(A) interpretation and reprocessing of legacy 2-D and 3-D seismic;

(B) review of aeromagnetic surveys, logs and pressure maps;

(C) identification of primary and secondary seals;

(D) ensuring that the primary seal extends over the area;

(E) assessment of seismicity and tectonic activity;

(2) legacy wells, whose investigation should include the

(A) number of wells penetrating the storage complex;

(B) age and construction of the wells;

(C) well status (producing, suspended, or abandoned); and

(D) history of well incidents and interventions in the area;

(iv) pore space ownership rights (identifying pore space owners in the area of review);

(v) proximity to and potential effects on other subsurface activities;

(vi) proximity to/potential effects on valuable natural, energy, and mineral resources;

(vii) handling and disposal of any brine produced by storage operations;

(b) surface criteria:

(i) existence of rights-of-way between CO_2 sources and the storage site;

(ii) existence of infrastructure, e.g., pipelines, access roads, and power lines;

(iii) population distribution overlying the storage site and along the path of the plume;

(iv) land ownership in the area of review defined by the regulatory authority;

(v) proximity to other industrial facilities and to agricultural activities;

(vi) proximity and exposure to vehicular traffic, roads, railways, or shipping traffic;

(vii) proximity to protected wildlife habitats and environmentally sensitive areas;

(viii) proximity to rivers and other bodies of fresh water;

(ix) proximity to national parks and other reserved areas;

(x) present and predicted development of adjacent properties;

(xi) site topography and variability in weather conditions;

(xii) cultural and historical resources; and

(xiii) socio-economic conditions.

5.4 Site characterization and assessment

5.4.1 General

The characterization of a storage unit and of the primary seal shall consider all forms of CO_2 movement and trapping for free-phase (supercritical, liquid, and gaseous) and dissolved CO_2. This may be achieved through the collection, interpretation, and, where needed and applicable, reinterpretation of all available data, including:

(a) seismic data;

(b) well test data;

(c) geophysical wireline data (cased and open hole);

(d) wellhead injection pressure data;

(e) aquifer or reservoir pressure data;

(f) data from core samples;

(g) analyses of sampled fluids (formation water, oil, and/or gas); and

(h) oil and gas production and fluid injection data (water, steam, gas, and solvents).

5.4.2 Geological and hydrogeological characterization of the storage unit

A geological and hydrogeological characterization of the storage unit to provide a reasonable estimate of capacity, injectivity, and containment shall be completed before injection for storage of any CO_2 stream. The characterization should include:

(a) assessment of lateral and vertical stratigraphic relations and properties of the storage unit;

(b) identification and characterization of structural features that could affect containment.

(c) determination of the three-dimensional orientation of the storage unit;

(d) mapping of the depth, top, heterogeneity and compartmentalization of the storage unit;

(e) assessment of porosity distribution in the storage unit using logs and core analysis data;

(f) evaluation of the initial pressure distribution in the storage unit;

(g) evaluation of injectivity, which is a measure of the rate at which CO_2 will be injected;

(h) evaluation of the background flow regime in the storage unit;

(i) evaluation of the potential total volume effectively available for CO_2 storage;

(j) development of a three-dimensional geological model of the storage complex;

(k) identification of the presence and size of known local traps;

(l) assessment of large-scale vertical and horizontal reservoir stratigraphic heterogeneity;

(m) evaluation of permeability distribution in the storage unit;

(n) evaluation of the temperature distribution in the storage unit prior to injection of the CO_2;

(o) estimation of wettability, relative permeability and capillary pressure;

(p) evaluation of the flow regime in the first permeable unit overlying the primary seal.

5.4.3 Characterization of confining strata

5.4.3.1 Primary seal

The sealing capacity of the primary seal shall be evaluated and qualified prior to injection of the CO_2.

(a) determination of the stratigraphy, lithology, thickness and continuity of the primary seal;

(b) evaluation of the thermo-hydro-mechanical integrity of the primary seal;

(c) identification of fractures, wells, and potential leakage pathways through the primary seal;

(d) estimation of the capillary entry pressure for CO_2 if the primary seal is water saturated.

5.4.3.2 Secondary barriers to CO_2 leakage

The presence of secondary barriers to CO_2 leakage shall be evaluated and include:

(a) identification of overlying saline aquifers and secondary seals that are present between the primary seal confining the storage unit and the protected groundwater;

(b) characterization of the aquifers within the storage complex.

5.4.4 Baseline geochemical characterization

The chemical composition of the CO_2 stream proposed for injection and of the fluids in the storage unit shall be characterized, as well as the composition of the fluids and the mineralogy of the rocks in the storage unit and in the primary seal. The characterization shall include:

(a) CO_2 stream composition;

(b) major and trace mineralogical components of the rocks in the storage unit and primary seal;

(c) composition of formation water and/or reservoir fluids/gases in the storage unit;

(d) formation water and rock mineralogy in the first permeable unit overlying the primary seal;

(e) additional baseline sampling of the geosphere and biosphere based on risk assessment.

5.4.5 Baseline geomechanical characterization

Geomechanical characterization of the storage unit and the primary seal shall be conducted based on well logs, in situ testing, or laboratory testing on preserved core material (where possible, other overlying units should be characterized). Geomechanical characterization shall include the following:

(a) evaluation of the natural seismicity and tectonic activity of the region;

(b) characterization of the in situ stress regime;

(c) determination of rock mechanical properties;

(d) development of a mechanical earth model.

5.4.6 Well characterization

Wells have been identified as a potential pathway for upwards leakage. Therefore, a characterization of the existing wells that could be affected by the storage operation within the area of review shall be performed and include:

(a) identification of the wells that penetrate the storage unit within the area of review;

(b) a determination of the status and ownership of the wells within the area of review;

(c) characterization of existing wells by construction type, and extent of mechanical defects;

(d) an evaluation of the potential of the wells to leak;

(e) identification of wells that penetrate higher horizons than the storage unit;

(f) chemical composition of well materials that will come in contact with a CO_2-charged fluid.

5.5 Modelling for characterization

5.5.2 Geological static model

5.5.2.2 Key modelling parameters

The geological static model shall describe the key geological, hydrogeological, geothermal, and geomechanical features of the storage complex, including:

(a) areal extent;

(b) stratigraphy, lithology, and facies distribution;

(c) structure tops and isopachs;

(d) geological features;

(e) porosity distribution;

(f) permeability distribution;

(g) the composition of fluids and rocks in the storage unit and primary seal;

(h) the initial pressure regime and distribution;

(i) the initial temperature distribution and geothermal regime;

(j) the initial stress regime; and

(k) rock mechanical properties.

5.5.2.3 Modelling outcomes

The results of the geological static model should provide key parameters for

(a) flow unit definition for the flow model;

(b) geological definition for the geochemical model; and

(c) geological definition (mechanical earth model) for geomechanical modelling.

5.5.3 Flow modelling

5.5.3.2 Key modelling parameters

Key modelling parameters should include the following:

(a) within the storage unit:

(i) initial pressure and temperature;

(ii) brine salinity;

(iii) equations of state for the fluids;

(iv) porosity;

(v) permeability;

(vi) heterogeneity and anisotropy;

(vii) formation geometry (thickness and dip);

(viii) relative permeability curves;

(ix) capillary pressure curves;

(x) fluid and rock compressibilities;

(xi) the thermal properties of fluids and rocks (in the case of non-isothermal modelling);

(xii) geomechanical properties (in the case of geomechanical modelling); and

(xiii) mineralogy and reactivity data (in the case of geochemical modelling);

(b) primary seal: permeability, capillary entry pressure, and other properties;

(c) fluids: CO_2 stream composition and concentrations, physical properties, and phase behavior.

5.5.3.3 Modelling outcomes

The results of modelling should provide information related to

(a) injectivity and injection scenarios (e.g., number and type of wells and well spacing);

(b) development of the CO_2 plume;

(c) movement and distribution of CO_2 in the storage unit;

(d) pressure buildup and areal extent;

(e) temperature distribution through the storage unit;

(f) movement of displaced fluids, particularly formation water (brine) in deep saline aquifers;

(g) partitioning of CO_2 among supercritical, liquid, gaseous, and dissolved phases;

(h) dynamic storage capacity;

(i) sensitivity analysis (which parameters have the greatest influence on uncertainty); and

(j) potential leakage paths out of the storage unit.

5.5.4 Geochemical modelling

5.5.4.2 Key modelling parameters

5.5.4.2.1

Key modelling parameters should include the following:

(a) storage unit:

(i) porosity; and

(ii) permeability.

(b) primary seal:

(i) porosity; and

(ii) permeability.

(c) solids:

(i) mineralogy and relative amounts of each mineralogical-lithological unit;

(ii) grain size;

(iii) thermodynamic database;

(iv) reaction rates, and

(v) experimental data.

(d) fluids:

(i) relative amounts of water, gas, and oil present;

(ii) water composition;

(iii) gas composition;

(iv) oil composition;*

(v) pressures;

(vi) temperatures; and

(vii) thermodynamic database.

5.5.4.2.2

With regard to experimental data, the following data may be collected to populate geochemical models used to determine the effects of CO_2 reaction with minerals in the short term:

(a) data from laboratory investigation of CO_2–water–mineral reactions in storage unit and seal;

(b) data from experiments on CO_2 flow/diffusion through a sample of the primary seal;

(c) data from experiments on reactivity of well materials for CO_2 and formation fluids.

5.5.4.3 Modelling outcomes

5.5.4.3.1 Modelling outcomes: Chemical reactivity of the storage unit

Flow is assumed to be the dominant transport process in the storage unit. The results of the modelling should provide information related to:

(a) the initial geochemical characteristics of the storage unit at in situ pressure and temperature;

(b) dehydration, dissolution, and precipitation reactions and fluid migration through rocks;

(c) the effect of long-term geochemical interactions with the CO_2 stream; and

(d) changes in formation fluid composition and phase behavior.

5.5.4.3.3 Modelling outcomes: Chemical reactivity of materials in existing wells

CO_2-saturated brine or water-saturated CO_2 will likely react with well materials (i.e., casings, cements, and bridge plugs), particularly if mechanical compromise allows fluids to migrate along the wellbore. For wells with minor mechanical defects, the following analyses and modelling should be performed to develop a life cycle monitoring and remediation plan:

(a) development of well defect models and modelling to predict well barrier performance;

(b) comparison of modelling results to laboratory tests to validate model predictions; and

(c) characterization of wells prone to defects to assess the need for monitoring or remediation.

5.5.5 Geomechanical modelling

5.5.5.2 Key modelling parameters

Many parameters required for geomechanical modelling are obtained in the development of the mechanical earth model and the flow model. The key geomechanical modelling parameters should include the following:

(a) geological model;

(b) initial in situ stress regimes;

(c) initial fluid pressure regime and distribution;

(d) constitutive properties of the mechanical stratigraphic units in the model; and

(e) parameters on geomechanical changes to the strength or pore structure of the storage unit.

5.5.5.3 Modelling outcomes

The results of modelling should provide information related to

(a) estimates of maximum injection pressure that will ensure no loss of integrity of primary seal;

(b) evaluation of the potential for fault reactivation;

(c) evaluation of the potential for induced seismicity;

(d) evaluation of the effect of geomechanical processes on injectivity;

(e) evaluation of wellbore stability during drilling;

(f) evaluation of deformation of storage unit, primary seal and overlying sedimentary succession

(g) evaluation of well integrity issues from geomechanical processes during injection/operation;

(h) sensitivity analysis (which geomechanical parameters effect greatest uncertainty).

8.3 M&V program objectives

Project operators shall develop and implement an M&V program suited to their operation. The M&V program should be defined according to the project periods specified in Clause 8.2 and shall be designed to serve the following objectives:

(a) to protect health, safety, and the environment throughout the project life cycle by detecting early warning signs of significant irregularities or unexpected movement of CO_2 or formation fluid

(i) through gathering information on the effectiveness of containment of CO_2 throughout the project life cycle; and

(ii) by providing sufficient evidence that the CO_2 has not moved beyond the storage complex, including leakage to a shallow subsurface zone or to the atmosphere;

(b) to support risk management throughout the project life cycle;

(c) to provide adequate information for

(i) decision support within the project (among the project operators and principal project partners) and for communication with regulatory authorities; and

(ii) communication with other stakeholders external to the project, including the local community or local landowners as appropriate;

(d) to test the predictions of dynamic modelling against observations documented from monitoring, enable adjustment of models to improve long-term storage performance predictions, determine the frequency and duration of monitoring activities, and support demonstration that criteria required for site closure are attained;

(e) to continuously improve the M&V program by adapting it to changing project circumstances, advances in best practices where appropriate, and advances in technology where appropriate;

(f) to support quantification calculations for injected and stored CO_2 in accordance with requirements identified for accounting purposes;

(g) to support management of CO_2 injection operations in a safe and environmentally responsible manner that complies with applicable regulations by gathering information that demonstrates that storage site operations are within the performance limits accepted by the project operator and the regulatory authorities;

(h) to support maintenance or improvement of storage system efficiency, safety, and economic performance;

(i) to support post-closure stewardship of the storage site (injection, closure, and post-closure), including assisting in transfer of responsibility in post-closure periods; and

(j) to support the achievement of project objectives and the preservation of project values additional to those specified in Items (a) to (i).

8.4 M&V program design

8.4.1 M&V program procedures and practices

The M&V program shall document

(a) the alignment of the M&V program with the project's risk management policy, and shall include accountabilities and responsibilities for monitoring activities that support the risk management plan;

(b) reviews of monitoring tools and monitoring activity performance, as appropriate, to inform the need to make changes to the monitoring program [see Clause 8.3(e)];

(c) communication of M&V requirements to internal and external stakeholders as appropriate;

(d) the allocation of appropriate resources to provide an assurance that monitoring activities are carried out in a diligent and timely manner;

(e) the explicit purpose and performance metrics for all monitoring activities; and

(f) the procedures for properly documenting the monitoring activities and the processes implemented for evaluating monitoring performance against the original purpose and pre-defined operational metrics.

8.4.2 M&V program required specifications

The M&V program shall be based on the planned CO_2 injection operation and include the following:

(a) the projected volumetric capacity of the storage units within the storage complex;

(b) the injectivity of the storage units within the storage complex;

(c) the planned rate of injection of CO_2;

(d) the total mass of CO_2 to be stored;

(e) the boundaries of the storage complex, including stratigraphic definition of the storage units and primary and secondary seals;

(f) the locations of planned or existing wells that penetrate the storage complex within the predicted area of influence;

(g) the manner in which the M&V program will fulfill requirements imposed by applicable regulations;

(h) the schedule and reporting procedures to document compliance with M&V requirements in applicable regulations or as imposed by or agreed with regulatory authorities;

(i) the sensor systems and human observations that provide objective data on system behavior collected at a frequency sufficient to support efficient operation under normal conditions and to help prevent or recognize health, safety, and environment (HSE) impact under upset conditions;

(j) the process and frequency for reviewing the M&V program, which shall include assessing observed performance against predicted performance, responding to changes in assumptions, and incorporating project lessons learned and changes to best practices. The process shall consider

(i) the frequency of updates to the program when observed performance corresponds to predicted performance; and

(ii) the frequency of updates to the program when observed performance does not correspond to predicted performance;

(k) the process and schedule for documenting M&V changes and updates;

(l) the risk-based ranking of scenarios that have the potential to cause significant HSE impact or to negatively affect storage performance, including the planned rate of injection, the total mass of injection, or the integrity of containment. This description should encompass the link between M&V design and any updated risk assessment results in compliance with the risk assessment criteria specified in Clause 6;

(m) all baseline measurements that have been obtained. Significant concentrations of CO_2 are commonly present in surface and subsurface environments and can vary daily or seasonally. Such normal fluctuations in baseline need to be determined to differentiate natural variations from leakage, as follows:

(i) at a minimum, baseline measurements shall be taken for every sampling position that will later be used for monitoring;

(ii) consideration should be given to having baseline measurements in areas where the anticipated pressure increases are sufficient to create a significant risk of leakage of reservoir brine into protected groundwater. In some cases, this may extend beyond the CO2 plume;

(iii) for surface-observable conditions subject to seasonal variation (e.g., soil gas determinations if chosen), a minimum of one year's observations shall be taken to account for such variation; and

(iv) concurrent meteorological conditions should also be tracked to properly document seasonal variations such as temperature, precipitation, and prevailing winds;

(n) the monitoring targets (or thresholds) for

(i) each ranked risk identified within the risk management framework;

(ii) identifying when there is a need for modifications to the numerical prediction models and monitoring protocols;

(iii) validation of criteria required for site closure are attained (see Clause 9); and

(iv) managing CO_2 injection operations, including the composition of the injectate, the injection rate, injection volumes, and reservoir pressures;

(o) the design of the monitoring program at the surface, in the biosphere, between the biosphere and the storage complex, and in the storage complex, specifying the assumptions and expected conditions for which the monitoring program is designed, the parameter changes that the program is designed to observe, and the timing (frequency) and duration of monitoring activities for each monitoring target for each monitoring period;

(p) the requirements for data acquisition from monitoring activities needed for integration into the project's predictive modelling program and the frequency with which this integration will occur. This description shall also identify how monitoring and modelling jointly support the project's risk management program. Predictive models shall be used with a description of the potential range of outcomes and should incorporate any associated degrees of uncertainty. The M&V program shall include a process for gathering and using information that could improve injection operational performance and storage safety;

(q) the decision criteria based on monitoring performance indicators used to determine whether the storage complex is exhibiting behaviour outside the expected range of performance;

(r) the schedule and process for verifying both storage integrity and quantification of stored volumes of CO_2; and

(s) the performance measures (i.e., criteria for evaluating the success of the monitoring program) to be met by all periods of the monitoring program, with statements of justification and a level of detail appropriate for the objectives to be achieved.

8.4.3 M&V program recommended specifications

The M&V program should take into consideration and describe the following:

(a) the applicable performance measures and purposes of monitoring during the different periods of the project life cycle, the monitoring technologies that will be used during each period, and the rationale for their selection. Technologies to monitor the following should be included:

(i) injected volume;

(ii) flow rate, injection temperature, and injection pressure at the wellhead;

(iii) composition of injectate;

(iv) spatial distribution of the CO_2 plume;

(v) spatial distribution of the elevated pressure zone;

(vi) pressure within the storage complex;

(vii) well integrity;

(viii) leakage outside of the storage complex;

(ix) integrity of the confining zone;

(x) extent of displacement of formation water in the formation;

(xi) pressure changes in deepest permeable formation overlying the primary seal above storage units;

(xii) potential induced seismicity or microseismic activity;

(xiii) geochemical changes in the reservoir that relate to risks from CO_2 injection or that enable validation of other observations such as those related to changes in permeability; and

(xiv) contamination of other resources that have been identified within an accepted area of review; and

(b) the methodology used to select and qualify monitoring technologies. The following elements should be included:

(i) defining monitoring tasks;

(ii) identifying potential monitoring technologies;

(iii) evaluating the effectiveness of technologies against the required tasks;

(iv) estimating the life cycle risk reduction benefits of available technologies;

(v) estimating the life cycle costs of available technologies (if desired);

(vi) a description of the placement of observation wells, if part of the monitoring system, and all monitoring activities associated with each such well;

(vii) the methods and frequency used to monitor changes in groundwater quality and composition from baseline in the lowermost protected groundwater; and

(viii) the identification and description of pre-existing wells in the storage complex that do not meet the requirements specified in Clause 7.3.7.

8.4.4 M&V program contingency monitoring

The M&V program should describe the following:

(a) pre-defined monitoring observations that would likely indicate conditions other than normal expected system performance. These observations will arise from

(i) measurements taken from individual instruments or methods;

(ii) qualitative observations; and

(iii) combinations or sets of measurements and observations;

(b) pre-defined observations for all baseline parameters measured;

(c) the operational changes more likely to be required, based on the occurrence of specific conditions other than normal operational parameters and the appropriate risk-based preparations to effect those changes;

(d) in the event of observations or conditions that are outside the anticipated range of parameters, the project operator's first response plan to check, confirm, and retake the observations, to the extent possible;

(e) the project operator's second response plan to follow up on the data checks specified in Item (d) in a broader sense to establish situational awareness based on all available information. The assessment of this information should be based on expert judgment, including experts from outside the project; and

(f) the project operator's third response plan to develop a remediation strategy including, if necessary, re-evaluation of risks, monitoring programs, and operations, based on the information gathered through implementing the second response plan.

References

Canadian Standards Association, 2012, CSA Group Z741-12 Geologic Storage of Carbon Dioxide: Mississauga, Ontario, October.